JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                     )
                                      ) Docket No.
Preparation of the 2007 Integrated    ) 06-IEP-1M
Energy Policy Report                  )
                                      )
Use of Portfolio Analysis in          )
Electric Utility Resource Planning    )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, JULY 11, 2007

1:05 P.M.

Reported by:
Peter Petty
Contract No. 150-07-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, IEPR Committee Presiding Member

John L. Geesman, IEPR Committee Associate Member

Jeffrey D. Byron, Electricity Committee Presiding Member

James Boyd, Electricity Committee Associate Member

ADVISORS PRESENT

Timothy Tutt

Suzanne Korosec

Gabriel Taylor

STAFF and CONSULTANTS PRESENT

Lorraine White

Michael Ringer

Bill Knox

Jonathan Lesser
Spencer Yang
Bates-White, LLC

ALSO PRESENT

Michael Schilmoeller (via teleconference)
Northwest Power and Conservation Council

Osman Sezgen
Pacific Gas and Electric Company

Raymond Johnson
Southern California Edison Company

Mark Minick
Southern California Edison Company

ALSO PRESENT

C.K. Woo
E3

Eric Wanless
Natural Resources Defense Council

I N D E X

P R O C E E D I N G S

1:05 p.m.

PRESIDING MEMBER PFANNENSTIEL: Good afternoon. This is an Energy Commission workshop in the Integrated Energy Policy Report proceeding.

I'm Commissioner Jackie Pfannenstiel; I'm the Presiding Commissioner on the Integrated Energy Policy Report Committee. To my right is Commissioner John Geesman, who is the Associate Member on that Committee.

To my immediate left is my Advisor, Tim Tutt. To his left is Commissioner Jeff Byron, who is the Presiding Commission of the Electricity Committee. And to his left is his Advisor, Gabe Taylor. To Commissioner Geesman's right is his Advisor, Suzanne Korosec. Do I have everybody?

This is a workshop on portfolio analysis in electric utility resource planning. A lot of information has been provided in exchange to date, so why don't we just get going. Lorraine.

MS. WHITE: Thank you, Chairman. This is the second workshop associated with staff's exploration of the use of portfolio analysis and its potential application in the California utility planning process.

We have issued a report that is currently available on our web that documents staff's review of portfolio analysis and issues associated with its application in California.

As part of our agenda today we will be providing a summary of he outcomes associated with the June 4th workshop. we will also be having a presentation from the Bates-White Company regarding the mean variance portfolio optimization of California's generation mix to 2020 specifically looking at 33 percent RPS achievement by that date.

We will be also listening to presentations from Southern California Edison on their take related to application of portfolio analysis in California. And specifically to their utility.

In terms of the staff presentations we're going to be focusing on implementation issues related to portfolio analysis; and if we were to actually do that, what it would take in California.

And, of course, as with all of these workshops we look forward to input and discussion with those in attendance. It is important for this proceeding in order to refine our analysis and develop appropriate policies.

Before we really dive into the agenda, by way of introduction, my name is Lorraine White. I'm the Program Manager for the Integrated Energy Policy Report. As I had mentioned the report associated with this particular workshop topic is available on our web, as is all information associated with this proceeding.

We do have a few kind of housekeeping item to cover briefly. The restrooms are out the double door and to the left. There's also a set behind the elevators. For refreshments we ask that you please go to the second floor. There's a snack shop there under the awning.

And then in the event of an emergency we ask that you calmly follow staff out of the building and to the park kitty-corner across the street. Wait there until such time as we're given clearance to return to the building.

Today's workshop, in order to facilitate participation, actually features several methods in which we hope to insure that people understand the materials we're covering today, and can engage in the dialogue.

We have currently on our website the Webex meeting services in which, if you follow the directions on the notice, as well as the link here going to our website, you can join us electronically that way. You can hear the audio; you can ask questions through the phone number that's provided here; and you can see the presentations that are actually going to be made.

And then, of course, we encourage folks to participate in person to the extent appropriate.

As part of this proceeding the portfolio analysis work actually is one of the fundamental assessments we're making. We're currently in the process of refining several assessments in various sectors of the energy area in California. Portfolio analysis is the way we are examining looking at the future and the way we do planning in California.

The information from this particular workshop, the report that's developed for this workshop, and all of the other workshops and documentations associated with other aspects of the proceeding are going to be compiled into a Committee document which we expect to be publishing in August.

The Committee report will be the subject of hearings and workshops in September. And a revised document will be published in early October for a late October adoption by the Energy Commission in time to be transmitted to the Governor and the Legislature by the legislative deadline of November 1st.

Contact information is available on our website, in particular related to portfolio analyses and our assessment thereof. Mike Ringer is the Staff Lead, and I encourage folks who have questions that may not be able to be answered at this time or you would like more background, please contact Mike Ringer.

Related to the renewables issues I also direct you to contact Bill Knox. For general information about the overall proceeding and other aspects of the energy sector we're examining I welcome you to contact me. And, again, that information is on our web.

If there are no particular comments or questions before we begin I'd like to hand the mike over to Mike Ringer. Thank you.

MR. RINGER: Okay. What I would like to

do is sort of provide a context of where we got to where we are now, and a summary of the June 4th staff workshop that we have.

Our whole effort began pretty much with the 2006 IEPR update which recognized that the method that utilities choose to evaluate their resources certainly has a tremendous influence on the portfolio that they ultimately will end up with.

And accordingly, the IEPR update recommended further investigation into analytical methods whereby technologies would be evaluated on their effect on the entire portfolio rather than their stand-alone attributes.

So, we began this the earlier part of the year. And this culminated as of June 4th in a workshop where we presented the context of our study and initial results. And following that workshop, as of about ten days ago, we did publish our draft staff report which has been posted on the web and is available out front.

A quick summary of the June 4th workshop. We did note that obviously there have been many changes in the environment in which utilities operate. Certainly since deregulation there's been a lot less certainty as to future resources that they can draw upon. The volatility of gas and electricity prices has increased quite a bit. There's uncertainty associated with merchant generation, as well as their future loads. They're subject to load migration, retail competition. And, in general, the complexity has increased greatly over the past many years.

Another aspect that I mentioned briefly is risks related to natural gas use. The volatility and the price has increased greatly. We don't know if it will revert to historic levels or not. The current levels of gas-fired generation in California, on an energy basis, are near 45 percent. So, obviously the trajectory that future gas prices follows will have a great deal of bearing on future prices in California.

And then more than 11,000 megawatts of baseload generation have come online in the past six years. A great deal of that is gas-fired.

Related to all this is the current constraints that the utilities have to operate under. Utilities obviously are required to do planning and report results to the CPUC. But they certainly don't have a free hand to do whatever they want to. There's many different constraints that they have to operate under.

These procurements plans that they have to file with the California Public Utilities Commission every two years, the utilities are required to talk about their price risk, the types and quantities of products that they need, whether it's energy or capacity.

They also have to operate under constraints having to do with renewable energy requirements, reserve margins, the loading order specified by the state, local reliability requirements, things like that. So they have a number of different things, different targets that they have to meet. And that's something that certainly does affect to a great deal the type of planning that they do and the leeway that they have in that planning.

There's been many concerns with the way that things have been going recently. As I mentioned, there's been a large amount of gas-fired resources that have been added in recent years. And if we do subscribe to the notion that future prices may be very high, this is indeed something that may be of concern.

Least-cost planning may have been the way to go in the past when things were a lot simpler and the utilities had a lot more control over what they could do, but right now, given the increased number and types of complexities that we have to consider, least-cost planning is certainly subject to debate as to how well it may serve California in the future.

Another concern is how future costs or present value may be unfair to renewables. There's a fair amount of discussion about the use of different discount rates when you look at different cost streams that have different risks associated with them.

And to the extent that utilities are currently a value-at-risk type of analysis, it's used in a fairly specific manner, such that it may not have a great deal of bearing on the future portfolios of the different utilities and the way those future portfolios are looked at.

To a great extent value-at-risk methodologies pretty much look at a specific portfolio where the utilities try to manage the risk of that one portfolio.

The next thing we got into in the June

4th staff workshop was a discussion of the modern portfolio theory. When we talk about portfolio, basically portfolio planning, or portfolio analysis, that means different things to different people.

But regardless of what an individual might think of a particular way of doing this, it all pretty much goes back to modern portfolio theory, which is a specific financial theory that was developed that basically showed people that the way to value a particular resource was to look at its effect on an entire portfolio. And not to look at that particular resource or cost in a vacuum.

It does focus on the overall portfolio risk and cost. And it purports -- derives an efficient frontier, so that you have different costs and risk combinations of portfolios.

So, for any portfolio you have a cost associated with it and a risk profile associated with it. So that for a given cost there is a least risk; and for a given risk there is a least-cost portfolio associated with that.

So you derive a curve, an efficient frontier of portfolios. And modern portfolio theory does not tell you where on the curve is the best place to be. That's up to the decisionmaker.

More expensive assets that are looked at by themselves, such as renewables, even if they were deemed to be more expensive by themselves, because of the risk profiles, they may be able to reduce overall portfolio risk and cost.

So there's a concern about how these renewables are valued and how they can be included in utility portfolios.

At the June 4th workshop we had a couple of presentations from the utilities, notably PG&E and SDG&E. And they described to us their planning methods.

PG&E stressed that their approach is grounded in multi-criteria decisionmaking. And their idea is that they look at a lot of the different metrics and attributes that we are interested in looking at through portfolio analysis. But it just looks slightly different the way they do it, but they're still interested in pretty much the same things.

They do examine tradeoffs between reliability and cost, and between environmental impact and cost, for example. They looked at four scenarios, three different plans and they assessed outcomes according to a variety of different metrics, including reliability, customer rates, renewable levels and CO2 emissions.

Their preferred plan was one that they described as increased reliability and a higher level of preferred resources.

San Diego Gas and Electric, they submitted one plan to the CPUC with base high- and low-need scenarios. And that's how they looked at theirs. Their resource portfolios were pretty much driven by state policy preferences, including the loading order, renewable portfolio standard and a lot of the constraints that I sort of briefly mentioned earlier. Their portfolios were driven also by reliability needs, load uncertainty and the term of commitments.

The next thing we did, we looked at the Lawrence Berkeley National Laboratory review of western utility resource plans. The Lab took a look at a couple of different plans, actually several different plans, from both 2005 and 2007 from the standpoint of how they treated renewable energy; and in general, how the planning process was undertaken by a number of different western utilities.

They found that there were many risks that were commonly evaluated. These included gas prices, wholesale electricity prices, retail load variations, hydro output and environmental regulatory risk.

A lot of the plans used both scenario and stochastic methods. And in general, the planning methods have become more sophisticated over time. But they did find that the portfolio construction was usually done by hand. And in a number of instances, the number of portfolios that they looked at, or that different utilities looked at were fairly constrained, a somewhat limited number of portfolios.

One of the conclusions from this study is that in general a larger number of portfolios should be considered.

Also, it matters a great deal the order in which you kind of look at things. For example, if you come up -- if you derive a large number of portfolios, what you don't want to do is try to screen things out too early.

In other words, if you have an idea that certain resources are high priced, you don't necessarily want to screen those out in an initial stage just based on that price. Because, as I mentioned before, modern portfolio theory has taught us that higher priced resources can, indeed, yield an overall portfolio that has lower expected costs and lower risks. So each risk of concern should have the opportunity to impact the portfolio selection.

Next we had a presentation by the Northwest Power and Conservation Council on their planning method. They are an interstate compact agency comprised of the States of Idaho, Montana, Oregon and Washington.

And they have to come up with a 20-year plan, which they have done, called the Fifth Northwest Electric Power and Conservation Plan. And they came up with a very sophisticated model way to do portfolio analysis planning, which is a strategic decisionmaking model.

And they're primarily concerned or concerned to a great degree with catastrophic outcomes and what sort of measures can you take to limit those catastrophic outcomes. What kind of adaptations improve the worst circumstances. That's what they have given emphasis to.

They also consider planning flexibility and that is a pretty good example, I think, of what this type of work can be. And I think it impressed a lot of people who were looking at it.

They tested a wide variety, 1400 different resource development plans or portfolios against 750 future. And through that they were able to generate quite an efficient frontier. And the measure of risk they looked at, again with the emphasis on the catastrophic outcomes, was called TAIL VAR 90, which is the average value for the worst 10 percent of outcomes.

So this is probably the most sophisticated method that we had seen, among all the different methods that we looked at.

Next, London Economics presented case studies for Ontario Power, PacifiCorp and the Canadian Energy Company to give us sort of a variety of slightly more in-depth view than what we got from Lawrence Berkeley Labs. And to give us kind of a flavor of the different types of methods that were used and the objectives.

So, very quickly, running over these. Ontario Power Authority. Their objective is not to provide an optimized portfolio, but to establish broad parameters for generation fuel mix. And this would be used in the future to provide a basis for future RFOs and RFPs.

Ontario constructed five scenarios with two plans for each scenario so they looked at ten portfolios in total. Now, each of these plans for the portfolios were constructed according to specified constraints. And it was, from what we understand, somewhat of a politicized process.

But they used a number of Monte Carlo runs to derive a distribution for the net present value of revenue requirements with costs being a primary focus. And within each of the five portfolios they examined which of the two portfolios performed the best.

At the end of this they also assigned environmental scores. And they generated a set of frontiers that could be qualitatively assessed. So it was sort of a variation on the theme where they took -- they did take scenarios and portfolios, but they were fairly limited.

PacifiCorp, on the other hand, is a vertically integrated regulated utility that operates in Oregon, Washington and California as Pacific Power; and as Rocky Mountain Power in

Utah, Wyoming and Idaho.

Every two years they develop a 20-year resource plan. And that resource plan is pretty much for the entire company. So they have to take into account the competing points of view of the two different companies.

They start with a reference portfolio to serve as a benchmark and then work off of that. As metrics, they included the present value of revenue requirements, capital costs, emissions, the amount of market purchases and sales and unit capacity factors.

They performed 100 simulations on each of 23 portfolios, generating fairly robust measures and creating a single efficient frontier by calculating cost and risk much as is done in any standard type of portfolio analysis.

Third and last is the Canadian Energy Company. And they did a study to take a look at their corporate strategy, as how they wanted to consider further development.

Their goal was to help determine medium- to long-term investment strategy. They looked at a small set of portfolios, each reflecting a specific strategic focus.

They also calculated expected average rate of return versus historical volatility for the five portfolios. And by that they constructed sort of a limited set of frontiers that could be compared quantitatively.

So at the end of the day after these three case studies there are four key questions that London Economics included. And that is from whose perspective is the analysis to be conducted. What was the appropriate objective function. That is the return metric. What is the appropriate geographic scope of the analysis. And who should conduct the analysis.

Now, as part of the preparation for the June 4th staff workshop we had published and put on the web a set of questions that we wanted to consider. And we've expanded that, which will be the basis for much of our discussion later this afternoon in the form of implementation issues.

So, David Vidaver will talk about that later. And we will have expanded the set of questions and concerns that we want to address here today.

So, with that, I think we'll go on. I guess we're going to switch to the slides, a different set of slides now, and have Bates-White come up.

ASSOCIATE MEMBER GEESMAN: Mike, before you go, have you put a written comment period on the report? Are you soliciting written response?

MR. RINGER: Yeah, we'd like to get written comments. I don't have the notice in front of me. It's probably on the order of 10 or 11 days, something like that. But, of course, we would try to get as many people to submit written comments, in addition to any verbal comments that they may have today.

ASSOCIATE MEMBER GEESMAN: I'm told in the notice it's July 19th.

MR. RINGER: Okay, thanks.

DR. LESSER: Thank you very much. My name is Jonathan Lesser; I'm a partner with Bates-White Consulting firm that was engaged by Bill Knox to try to do, take a first crack at an actual portfolio analysis for California in recognition of the 33 percent renewable generation goal for 2020.

I'll talk briefly, the background purpose, benefits of a portfolio analysis approach, the description of the methodology we used, how we evaluated the proposed 2020 business-as-usual generation portfolio. And analysis of our alternative generation portfolios that we examined.

Basically we stepped back to a policy perspective that renewable resources have potential benefits. There's little fuel price risk with the exception of biomass, so it can offer price stability to ratepayers.

On the other hand, utilities may have little or no incentive to reduce their fuel costs if those costs are passed along automatically to consumers. Of course, there are regulatory mechanisms that encourage better performance.

It's also the case that it may be that stand-alone costs for some renewables are lower than a fossil fuel resources. Of course, the environmental benefits, which is one of the major policy drivers for California's 33 percent goal.

There's also that reduced dependence on fossil fuels, greater energy independence, which some folks recognize as a key policy goal.

The 33 percent renewable resource goal was put in by AB-32, and adds some urgency to combat climate change. The interim goal is 20 percent renewables by 2010, which apparently the renewable energy supplies today are roughly 11 percent.

Now, last year's IEPR concluded that California, in fact, was unlikely to meet its 2010 goal because of five barriers to renewables. One was the inadequate transmission infrastructure to connect remotely located renewable resources.

Two, uncertainty regarding whether projects with supplemental energy payment awards will be able to obtain project financing. The complexity and lack of transparency in the renewable portfolio standard program. And the implementation for investor-owned utilities.

Insufficient attention to the possibility of contract failures and delays. And lack of progress in repowering aging wind facilities.

Another potential barrier, of course, is cost. That some renewable resources are more costly on a stand-alone basis than fossil-fuel alternatives.

Given that, what we wanted to do is demonstrate in sort of a first cut, a mean variance portfolio optimization with placeholder inputs; those being the inputs provided by some of the previous California policy work in terms of resource costs.

And the approach we used was the mean variance approach, which is similar, if you're familiar in finance, with capital asset pricing model. It's that same sort of Markowitz mean variance portfolio optimization.

We did identify efficient frontiers which essentially look at the best possible tradeoffs between expected costs and risk.

And one of the key questions we wanted to address was is the business-as-usual portfolio that's been posited by California an efficient portfolio. Does it lie on that efficient frontier.

And if not, and in fact, as I'll show in a little bit, it does not lie on the efficient frontier, what that means is that California can do better by reducing both expected resource costs in the future, and risk.

Now, there's several caveats before I present the results of our analysis. We used just essentially placeholder values for the upper and lower bound amounts of renewables that could conceivably put in. There's certainly a lot of realistic constraints on just how much renewable resources you can invest and install. There's technical and economic potential issues. There's issues associated with do renewables from out of state qualify under the REC program.

You'd also, in a more complete analysis, want to consider transmission and integration constraints at a regional and local levels. And there are ways to do that.

And also we've had to make some basic assumptions that the volatility, the riskiness, say, of fuel prices, capital costs in the future will be the same as they have been in the past.

Now, there are ways and methodologies that can isolate those uncertainties that matter most and address changing uncertainty over time. And I'm happy to discuss that with you later on if you like.

Some of the other limitations of our analysis that are important to understand is that any mean variance portfolio analysis essentially assumes a very specific risk structure. It essentially assumes that risks are symmetric. You have a nice bell-shaped curve. And that way variance captures all the risk attributes.

If risks are asymmetric, however, then mean variance portfolio analysis starts to break down. And in the case of a lot of energy resources and some of the key uncertainties, in fact it's probably unlikely that the risks will be, you know, can be accurately described in a nice bell-shaped curve manner.

Our analysis also did not include certain risks. We did not try to take account of wind resource intermittency and transmission stability issues that might limit how much wind could be installed in any one location. And we also ignored the wind saturation levels at the local level.

We also ignored geothermal steam resource constraints. So I know there have been concerns in the past about decreases in steam production at say the Geysers. We didn't try to consider that in our analysis.

We also did not address other nonlinear impacts. And what this means is that once you start adding too many renewables, cost and risk, both increase. It's not as if you just increase renewables and risk goes down and down and down.

That doesn't happen.

At some point it turns around, and suddenly risks go up. And unfortunately the results don't follow a nice linear transformation. it can happen very suddenly.

We also did not try to account for price interactions associated with changing supply and demand of different resources. Technology costs are going to be affected by resource constraints. Fossil fuel prices are going to be affected by the actual decisions, investment decisions, generators make. And essentially that increases the non-linearity or the messiness, if you like, of the analysis.

In terms of the benefits of portfolio analysis, one of the key benefits that we see is that whenever you're looking at some sort of, say a scenario analysis, a sensitivity analysis, you really want to consider what the volatility is going to be. And how that volatility has increased over time. What the uncertainty is over future environmental policies.

And it's important to know essentially when you forecast out in the long term, the one thing you can be sure of is that you're going to get it wrong. And so what's beneficial to know, what are the costs of being wrong.

You also want to know how do different resources interact. How they interact may be very different than just looking at them on a stand-alone basis.

So what we'd also like to find out is what's the value of using renewable resources as a financial hedge against future market volatility. And what's the point where that hedge value is greatest.

And finally, essentially a stand-alone analysis throws away useful information. Whenever you do, say, a simple scenario analysis or sensitivity analysis, if you don't consider the overall probability distribution you're throwing away useful information. And that information is already there.

So, given those uncertainties, what you want to do is identify essentially a least-expected cost portfolio. And although that's probably impossible, you can, at least, identify portfolios and their different risks.

I'm not going to go through really -- this has probably been covered in your previous workshops on modern finance area and portfolio analysis. There's obviously no -- the key take-away point here is that there is no one right answer.

Investors have different risk tradeoffs; they have different degrees of risk aversion. And it's the same probably for policymakers in this context of energy planning. What's the right amount of risk to take. And what essentially should the state be willing to pay to avoid that risk. That's a very tough question to answer.

However, one thing you can do is at least identify what are the best alternatives and make your tradeoffs amongst those alternatives only.

Now, in the case of renewable resources, another benefit of portfolio analysis is that they will have their highest payoff when fossil fuel prices are at their highest. So, if you look at, for example, solar photovoltaics. When fuel prices decrease, consumers are better off anyway, but the value of solar photovoltaics falls. On the other hand, if fuel prices are very high, consumers are worse off, but the value they get from solar PV increases.

In finance theory that's known as a negative beta asset, i.e., one whose value is inversely correlated with the value of the market. And stand-alone analysis will ignore that head value.

So, again, our approach is based on mean variance analysis. Variance, just to be clear, measures the dispersion of a probability distribution. And standard deviation, which we refer to a lot, is just the square root of the variance. Sorry about that.

The basic comments -- I think Bill did something to my presentation -- that equation is supposed to be down there. That's all right. I can't move it.

What's going on here is I'm just trying to show basic concept that when you're looking at a portfolio of resources the overall riskiness of that portfolio depends on the combination, how the different, the individual assets combine and interact.

The key term is, in fact, this value row sub-1-2. That's the covariance term. It's a correlation coefficient. Actually equals covariance divided by the product of individual standard deviations.

And why it's significant is that if that row value, if that correlation coefficient is negative then the overall portfolio risk is, in fact, less than the individual asset risks considered separately.

So what you really want to identify is what portfolio of resources can best identify those negative correlations.

So, again, you might have a two-resource example. The solid blue line is that efficient frontier; whereas even if you have 100 percent of technology B, you have a lot of risks, low cost. If you have 100 percent of technology A, you have less risk but a higher cost.

When you start combining the two you can actually lower both your costs and risk because of that inverse correlation.

How do renewable resources reduce costs and risk? Again, essentially what -- think of it this way: You can start with your fossil portfolio. If you add then renewable energy technologies, that will reduce your price volatility each year, but it could increase costs.

But when you remix it to the same level

of risk that you had with the fossil portfolio, you can, in fact, lower your overall expected costs.

The next thing we did was look at the business-as-usual generation portfolio. And this is a summary of the stand-alone costs associated with that portfolio based on the CEC Staff report and some European information from Tech Pol. This assumes a $20 per metric ton CO2 cost.

And, again, as you can see, solar photovoltaic very expensive. Yet it can have significant risk reduction benefits.

There's really four types of stand-alone risk parameters that we considered. One is the investment, the capital cost risk. For existing resources, they're built, they obviously have no cost risk; at least capital cost risk.

New resources. We looked at World Bank reports, developer interviews in terms of what they thought the volatility capital costs would be for building new resources. Fuel cost risks. Again, for renewables it's all zero except for biomass. For fossil fuel and nuclear resources we looked at analysis of historic U.S. price data from the Energy Efficiency Administration and

FERC.

For nonfuel operations and maintenance costs risks, we looked a data collected by the Energy Information Administration. Turns out that nonfuel operation and maintenance risk is really insignificant. This is one of those things that you could very safely just ignore in future analysis, could it really does not drive any of the results.

And finally, CO2 cost risks. There's clearly uncertainty as to what future CO2 costs will be in terms of we don't know really what sort of CO2 regulations might occur in the future, if any. Would they be an emissions stacks, cap-and-trade programs, some combination of both. You don't know implementation dates, the stringency, how much the tax or cap-and-trade might be set to reduce emissions to, et cetera.

Quick summary of the stand-alone risk parameters. Again, we identified the highest cost risk for investment associated with new nuclear plants; somewhat of a moot issue for California since there's a prohibition on adding new nuclear power. Also large risk for new coal plants.

Fuel risks. Again, it turns nuclear is

the highest risk, even greater than natural gas because in the last year nuclear prices have gone up so much. And over the last six years nuclear prices have actually increased by 800 percent.

The next thing we looked at after these stand-alone price risks was the correlation coefficients between those different risks. So, for example, if you look at the risk between future CO_2 prices and fossil fuel prices, intuitively you might expect that as the CO_2 costs increase that's going to reduce the demand for all fossil fuels. And so you could then conclude, aha, CO_2 prices and fossil fuel prices are going to be negatively correlated.

That, however, is not the entire story, because CO_2 prices will affect high carbon resources like coal more than lower carbon resources like natural gas. So what you can find is that a higher CO_2 price causes substitution to lower carbon fuels like natural gas away from coal. And the net result is that you can see a CO_2 price that's positively correlated with natural gas prices.

On the other hand we tend to observe negative correlation between prices of nuclear fuel and the prices of a fossil fuel.

The table below shows the fuel price correlation matrix Notice I've just highlighted some of the negative correlations between say uranium and coal prices and the very high correlation factor we estimated between CO2 and natural gas prices.

It does suggest that there's some other opportunities for risk diversification, given some of these negative correlations.

The way we come up with a total portfolio cost estimate is essentially we take that formula that takes the, adds the individual asset variances, the individual risk variances and their correlations. And we weight them, those weights X1, X2, et cetera, by the proportional values in the levelized cost components.

So, for example, if capital costs are 25 percent of the entire cost mix, then the weight for capital cost is 25 percent, and so forth. And so the result is a map of individual generating resource expected costs and risks.

The next slide is just the comparison between the existing and 2020 business-as-usual generator mix in terms of total supply. In either case natural gas is going to play a very large role. Nuclear still plays a role. And you're seeing generally an increase in only renewables.

Now, what we looked at, we estimated -- in this slide you can see the 2006 portfolio of average costs per kilowatt hour, and the year-to-year standard deviation. We estimated of that cost -- we then analyzed that with assuming a $20 carbon tax. And we looked at the California 2020. This point is the business-as-usual portfolio.

Now, keeping that in mind we then began our analysis of alternative portfolios. Now, clearly there's an infinite number of portfolios you could probably come up with. So, what we wanted to do for this exercise is limit our analysis to essentially what we call boundary portfolios relative to the business-as-usual scenario.

So we developed four different portfolio alternatives. Mix P was a high-cost, low-risk portfolio. It had great resource diversity. As a result it had higher costs.

Mix N was designed to have the same cost as the business-as-usual mix, but the lowest possible risk. Mix S, on the other hand, was intended to have the same risk as the California BAU, but have the lowest expected cost.

And finally, mix Q was intended to be the lowest cost, but highest risk portfolio. Essentially it's a much less diverse resource portfolio.

Again, we did not address certain resource constraints and risks such as with wind power and geothermal. And essentially this slide gives you a picture of what the portfolios we did look at, how they compared with the 2020 business-as-usual mix.

So, again, here's the 2020 mix. We found that we could identify mix N as having, in fact, a lower portfolio risk for the same expected cost. We also found mix S having a lower expected cost for the same risk.

So, what that means is that anywhere between these two points, between mix N and mix S, those are essentially what are called dominant portfolios. Any portfolio you chose between these two points would have both less risk and lower expected costs. So it's a win/win situation.

Now, we assumed there'd be no new investment in coal, nuclear and large hydro generation. We allowed up to 30 percent of new gas-fired generation. We allowed up to 10 percent each of the total portfolio for new biomass, biogas, small hydro and solar. We had up to 25 percent new geothermal. And the question that you see there, it's essentially 25 percent of the new generation, and up to 30 percent wind. This is just a table that summarizes those boundaries.

And the next slide gives you an idea of here the different stand-alone costs. For example, on a stand-alone basis for geothermal you'd have a pretty low risk and low cost.

So in one sense you might say, gee, I want all geothermal. Can't I have a portfolio with just geothermal and say just wind because it's also a very low risk, low cost in our analysis.

And the answer, of course, is no, you can't have that because you need to have a diverse portfolio that can also meet reliability needs.

Summary of the costs and risks of the alternative portfolios. This just gives you the numbers associated with this chart and the different generation shares. It's interesting to note is that portfolio S down here with the lowest cost had a total of 64 percent of generation share was renewable. So that's a significant amount of generation.

And even under portfolio P and N, which are the ones that bound the 2020 mix -- I'm sorry, actually N and S bound it -- we're showing greater amounts of renewable resources compared to the 2020 goal that's been established of 33 percent. We're showing between 45 percent and 41 percent -- sorry, 45 percent and 64 percent.

This graph just summarizes the different technology share in overall CO2 emissions. Again, all the portfolios we selected, in fact, have lower CO2 emissions than the business-as-usual mix.

Our key findings were that the share of renewables could be increased from 20 percent to 45 percent without an increase in expected portfolio costs. We also found that -- and that would be going from the 2020 business-as-usual mix to portfolio N.

And that portfolio N also reduces CO2 emissions by 31 million tons per year relative to the business-as-usual portfolio.

Our analysis also showed that you could

get up to 64 percent renewables and still decrease the overall expected cost. And that would reduce CO_2 emissions by 59 million tons per year.

Now, unfortunately the precise relationship between the technology shares of the renewables, CO_2 emissions and the cost and risks that's very nonlinear. And so, in fact, if you start increasing those renewable shares too much, then you start increasing both costs and risk.

So essentially what you do, if you start increasing the renewable share eventually you'll start moving back up to the north and east on this chart.

Now we also looked at some alternative nuclear policy. We wanted to see whether a policy of promoting nuclear power in the state, contrary to existing state policy, could, in fact, reduce overall risks and costs.

So what we did is we evaluated portfolios containing up to 10 percent of new nuclear generation. We didn't change the generating constraints, the resource constraints on any of the other resources; and we assumed a CO_2 tax of $20 a ton.

Now what we found is that, in fact,

adding new nuclear technology would shift the efficient frontier outwards. It would make things worse. So you ended up with higher costs and higher risk.

The next slide just summarizes the different generation resource shares. And we just increased nuclear from the 12 percent existing in the business-as-usual case by another 10 percent. So it, in fact, was roughly 22 percent in three of the four portfolios, and 20 percent in portfolio Q.

You see the same pattern of CO2 emissions. Again, the 2020 mix still has higher overall CO2 emissions than any of the alternative portfolios, even under this new nuclear case.

We also look at analysis of what would happen if CO2 prices increased. And not surprisingly we found that higher CO2 prices are also going to increase cost and overall risk.

And we also show here, you can see essentially the effects of moving from a carbon tax of say $11 to a carbon tax of $30, how the business-as-usual portfolio changes in terms of costs and risks. Risk goes up and expected costs increase.

So, the summary of our analysis. Given the limitations and caveats of the analysis, it shows that first evaluating resources in a combination portfolio basis can be very beneficial compared to stand-alone comparisons.

Renewables can be more expensive on a stand-alone basis, but they can still reduce expected costs and risks.

It's our belief that sensitivity and scenario analysis are inadequate, and in fact, error prone. That they will not necessarily capture key portfolio impacts.

And we believe that increasingly uncertain energy markets mean that it's far more important to use either portfolio analysis or other probablistic methods.

And finally, our analysis shows that, based on this, California policymakers can improve both costs and risk from the proposed business-as-usual portfolio.

We have some recommendations for further research. One is obviously to incorporate some of the additional risks, including asymmetric risks. We think that's very important to allow that, and essentially adopt a slightly different modeling approach that would allow us to address asymmetric risks in the analysis.

Another key point is far more detailed analysis of wind resources at the local level. That can be done by adding more localized wind resources. Instead of having essentially one resource in the mix, you have multiple wind resources representing different locations and having specific constraints.

Another key thing you'd want to look at is to incorporate fuel and technology costs feedbacks. For example, fuel prices tend to follow what's called mean reversion. As prices go up, demand goes down. Prices start dropping, demand goes up. Prices go up -- so it follows a sort of a harmonic kind of approach.

Certainly additional research on nuclear technology costs and risks might be appropriate. It also might be appropriate to develop what we call a no-regrets analysis.

So, suppose that natural gas prices really do decrease a whole lot. That there's huge new discoveries of natural gas, prices go down. Does it still make sense to pursue a policy of significant new renewable resources development.

And if so, what would that policy look like.

Finally, we suggest adopting more of a decision model, a dynamic programming approach. Because rather than a snapshot of here's what's going on in 2020, what would be more important is to really look at, well, how do you go from here to there. What decisions do you need to make now to reach those goals in 2020. And also to identify what uncertainties matter, what uncertainties don't matter.

Thank you very much. Happy to answer any questions.

ASSOCIATE MEMBER GEESMAN: I just wanted to confirm that cost assumptions that you're using for different technologies, such as nuclear, are those that we'd published earlier in our staff cost-of-generation study?

DR. LESSER: Yes, that's correct.

ASSOCIATE MEMBER GEESMAN: What would be an example of something that you'd characterize as an asymmetric risk?

DR. LESSER: Well, future carbon prices regulations. For CO_2 regulations there's two uncertainties. One is what kind of regulation might you get, and when would it be implemented.

And what level of regulation would occur.

So, for example, you might expect that if a CO2 tax were implemented a year from now, say, it would likely be at a lower level than one that was implemented five years from now. So that's an example of asymmetry.

You'd also find that with technology costs. You'll probably get a lot of asymmetry there. Costs can be a little lower than people expect, or as is more likely, things happen and the cost, the capital costs associated with installation -- and that's even true with existing technologies -- can be much higher than expected because there's so many site-specific issues.

Steam supplies from geothermal; wind intermittency is probably asymmetric. So there's a whole lot of asymmetric risks out there.

The other thing that's probably important to consider is when you start having these risks interact, the ultimate outcome of that is essentially a probability distribution that is almost certainly not going to look like a nice normal bell-shaped curve.

ASSOCIATE MEMBER GEESMAN: If I could assemble a portfolio of capital investments in the efficiency area, where efficiency improvements or energy savings could be expected to endure over your period of analysis, would it be safe to conclude that the same type of approach that you've taken to evaluating renewables in the portfolio would apply to that portfolio of efficiency improvements?

DR. LESSER: Yes, it would. And in fact, what I would do is not analyze efficiency improvements separately. I would include them as part of an overall portfolio analysis.

ASSOCIATE MEMBER GEESMAN: Thank you very much.

DR. LESSER: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Jonathan, before you go away.

DR. LESSER: Oh, I'm sorry.

PRESIDING MEMBER PFANNENSTIEL: That's okay. Your conclusions from the analysis you did, the striking conclusion about share of renewables could be increased to 45 percent, I think, with lower costs, how robust is that conclusion, given the assumptions that you used? And as you pointed out, there's some heroic assumptions you needed to use for some of the modeling that you did.

DR. LESSER: I would say it's a fairly robust conclusion in light of the heroic assumptions. So, --

(Laughter.)

DR. LESSER: -- I certainly, if I were in your shoes, I would not go to the bank with that because of the assumptions we had to make for this analysis.

I think there are, you know, it's going to be very important to essentially look at the wind integration costs and the transmission reliability stability issues, saturation issues.

I would want to do a lot more work on getting that right before I made that conclusion. Just simply citing issues of could you, in fact, build this stuff, what would the capital costs look like. And that's a lot of wind generation, for example.

And while General Electric is going to be, you know, salivating if you make that decision because they'll sell a lot more generators, that means the costs of technology is going to go up.

We've seen that, for example, in solar photovoltaics where Germany's feed-in tariff is so high for solar that it's, in fact, driven up the price of PV quite a lot.

So those are all impacts you'd want to look at much more carefully. And, again, I think that's why a more dynamic programming approach that looked at more flexibility and flexible decisions so you could react to things as they change makes a lot more sense.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Yes, Jeff.

PRESIDING MEMBER BYRON: Dr. Lesser, my fellow Commissioners honed in on the same two subject areas that I was interested in. And clearly, I would think if we don't have any constraints on the amount of renewable penetration we can have on the grid and the intermittency issue, clearly renewables are going to continue to look more and more attractive, as you indicated your analysis would prove out to be correct, based upon those two assumptions.

Going back to the nuclear one a little bit more, I thought I heard you say nuclear prices had increased 800 percent recently?

DR. LESSER: Nuclear fuel prices, since about 2001. They've actually doubled this year, alone.

PRESIDING MEMBER BYRON: Okay.

DR. LESSER: The reason is there were several incidents, essentially flood of uranium mines. One in Australia; one in Canada. And together those accounted for over 20 percent of all nuclear fuel output, supply.

PRESIDING MEMBER BYRON: Right, and I believe that's correct. I was under the impression that you were increasing all costs associated with nuclear --

DR. LESSER: Oh, no, no, no, no, no. We maintain the same volatility of nuclear, the actual capital cost uncertainty. But we recognize that the volatility of nuclear fuel prices is quite large.

And, in fact, I think that's probably an overstatement of nuclear fuel risk because of what's gone on in the last year. And I think the actual volatility is probably somewhat lower.

PRESIDING MEMBER BYRON: Dr. Lesser, this is wonderful work. Thank you very much for bringing it to us today.

DR. LESSER: Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Boyd, did you have a question?

ASSOCIATE MEMBER BOYD: I did; thank you for allowing me the interruption here. I've been listening from the sanctity of my office and watching, although the charts on the screens of our computers are quite small; strained my eyes pretty good. But I didn't attend because I thought I was going to have to be somewhere else today that didn't develop. But I have found this very fascinating obviously.

I wanted to ask a question about biomass and maybe another one about biogas. Something we wrestle with here, and those of us pursuing this subject a lot, is the economics associated with biomass.

And you earlier commented about prices and uncertainty when it comes to the fuel for biomass.

In California, in particular, the source for our biomass, to a large degree, can be and is waste material. And there are societal benefits associated with utilizing that material we're finally beginning to wake up to, like get the stuff out of the forest and maybe you won't burn the forest down. And help the farmers get the material out of the field that they can't burn anymore. Or use food wastes, et cetera, et cetera, urban wood waste.

But the difficulty we've been having is you can't, you know, there's no cash associated with that on the front end; and you can't make a good economic argument for utilizing those fuels. At least we haven't been able to yet.

How did you, or how do you deal with that in an analysis like this where we're slowly making our way towards policymakers beginning to see this, but not knowing how to move the avoided costs from one place to another? And the realities of today, when that doesn't happen yet?

DR. LESSER: Are you asking me from an analytical standpoint or a policy standpoint?

ASSOCIATE MEMBER BOYD: A little of both, I think.

DR. LESSER: Okay. Well, from an analytical standpoint what you could do is look at how does it matter, you know, essentially what levels of biomass fuel costs start to really make a difference, where you say, gee, I don't want any more biomass, or I want as much as I can get.

That would give you an idea of what might you be willing to pay to obtain new sources of biomass fuel, such as let's say clearing deadwood out of the forest to reduce the forest fire hazards.

In that case you might say, you know, we could pay, for example, analytically you'd say what's the damage we're getting every year from forest fires. Maybe you conclude in a typical year the damage is say $500 million in firefighting costs, pollution, lack of tourism, whatever else that might go on.

Well, if you'd say that now if I could clear that stuff out and reduce the expected forestfire damage cost say to $200 million, $250 million, cut it in half. Then what that would tell me is the state could pay someone up to $250 million to remove that and use it in biomass and be just as well off.

In fact, probably better off because you'd reduce the likelihood of real catastrophic forestfire events.

So, what you might then to is say, all right, we will pay you up to a certain amount per ton to remove this from forests and use it in biomass, you know, waste-burning facilities.

So that's kind of an economic analytical and policy approach.

ASSOCIATE MEMBER BOYD: Thank you. That's exactly what I was looking for, and I appreciate that being in the record. I'd like to use that record in some other forums these days, particularly in light of the fact that our Legislature refused a budget proposal to deal with the biomass in the Tahoe Basin recently. And now we have an I-told-you-so dilemma up there.

But, in any event, thank you.

DR. LESSER: You're quite welcome.

ASSOCIATE MEMBER BOYD: Well, biogas real quick. I notice the very low cost associated with biogas on your chart. Is that because you took into account in your carbon tax analysis of the fact that capturing biogas is capturing methane and keeping it out of the atmosphere?

DR. LESSER: I'm going to turn to my analytical wizard for that one, because I'm not sure exactly. The biomass costs?

ASSOCIATE MEMBER BOYD: Biogas.

DR. YANG: Biogas (inaudible).

DR. LESSER: Okay. So it's from the California cost of generation.

PRESIDING MEMBER PFANNENSTIEL:

Commissioner Boyd, would you like to join us up here?

ASSOCIATE MEMBER BOYD: I'm going to retreat to the sanctity of my office again, though thank you.

PRESIDING MEMBER PFANNENSTIEL: Tim.

MR. TUTT: Thank you, Dr. Lesser, for this very fascinating analysis. Didn't mean to turn the lights out when --

(Laughter.)

DR. LESSER: You're in the dark, Commissioner.

MR. TUTT: And I'm not a Commissioner, I'm an Advisor, thank you --

DR. LESSER: Oh, -- I'm sorry.

MR. TUTT: I wanted to clarify that the cost information that you're using from the cost-of-generation report, it's all from there except for the solar photovoltaic costs which follow the assumption we used in our scenario analysis of 50 percent of today's costs, I believe.

DR. YANG: That's correct.

DR. LESSER: Okay, thank you.

MR. TUTT: And then the second question was where did you get your risk information or risk numbers that are in the tables in the report and that you showed in your presentation?

DR. LESSER: The fuel costs risks we derived out from using energy information administration price data. The technology cost risk is based on a combination of European technical data and Energy Information Administration price data. And the O&M cost risks, that is also EIA, is it not, and some European data?

DR. YANG: That's from the (inaudible) --

REPORTER: Could you come to a microphone, sir, if you're going to speak. I can't get you on the record.

DR. YANG: The investment cost risk is based on the couple of analyses done by World Bank, as well as the Sandia report. And fuel cost is coming from the, to the extent available, cost-of-generation spreadsheet that CEC used for the wholesale forecasting. And O&M cost is coming from the energy velocity database, which is actually aggregating the public information from EIA, as well as the Federal Energy Regulatory Commission data.

MR. TUTT: And then are those risk estimates multiplied together in some equation in the model?

DR. YANG: Yes, weighted by the weighting factors, that's correct.

DR. LESSER: That was one of those equations that was floating at the top of the slide.

PRESIDING MEMBER PFANNENSTIEL: Sir, would you put your name into the record so we can get it correctly.

DR. YANG: My name is Spencer Yang; Manager at Bates-White. Now, I like to also point out that the presentation is kind of little bit old version; therefore the cost information that is shown is outdated. That's not the actual cost information that we used in the portfolio analysis. And if you look at the actual -- the report, the draft report actually correctly captures the cost information. Sorry about the confusion.

PRESIDING MEMBER PFANNENSTIEL: No other questions up here?

MS. WHITE: Michael, if you could please ask your question now? Your mike has been released.

(Pause.)

PRESIDING MEMBER PFANNENSTIEL: Okay, nobody's there?

MR. SCHILMOELLER: Michael Schilmoeller.

PRESIDING MEMBER PFANNENSTIEL: Okay. Do you have a question?

MR. SCHILMOELLER: Just a comment. Perhaps you're already aware of this, but the Northwest Power and Conservation Council, the organization I represent, and Bonneville Power Administration are about a year into a regional analysis of the impact of wind and wind integration on our plan.

You may recall from the presentation I made last time I was there, that wind features quite prominently in the plan. We have about 6000 megawatts of wind coming into the region.

And as a consequence, there was a regional forum established to look at issues like integration costs, transmission constraint, needs diversity, wind forecasting.

And as I say, it's about a year along. And just wanted to make sure that people are aware of the fact that that information will be available to you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Are we opening to public questions now? Comment?

MS. WHITE: At this time there's no further questions on the Webex --

PRESIDING MEMBER PFANNENSTIEL: Yes, but we have some in the room.

MS. WHITE: Right, but not on the Webex.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Please, go ahead.

MR. SEZGEN: This is Osman Sezgen with PG&E. I have a technical question first before I make a general statement.

If you could go back to slide 18, please. My question is regarding we started with a fossil portfolio here; and then isn't it true that in order to reduce the cost of the new portfolio, you have to remove from the existing some items which are more expensive than the renewables you put in?

Because I understand mixing diversification reduces the standard deviation, but the expected value cannot be lower than the lowest item in the portfolio. So you must be removing some other, more expensive items in there so that your expected value is coming down in three. And it's not only the effect of the standard deviation.

DR. LESSER: You're absolutely right, yeah. Sure.

MR. SEZGEN: Thank you. I also want to talk about some concerns we have about the portfolio, portfolio theory, actually. At PG&E we already use portfolio analysis. We analyze our plans under that framework.

But the specific construct, we have issues with that in the following areas: The first one is, first of all, as I mentioned a few days ago we wanted to look at the impacts of our plans on cost, risk, reliability, GHG and how the demand fits with the generation supply. And looking at those in detail.

Now, the way the electricity markets are, are demand and then most of the generation has a diurnal and monthly pattern to it. And it seems to me that this construct here is ignoring those patterns and working in an annual fashion.

So, another general question I have is how is the demand model in this framework, and is it only an annual number, or is the pattern represented relative to the generation patterns? If you'd like to take it --

DR. LESSER: I'll try to answer. Essentially in this analysis that we did, we did not consider demand uncertainty; because it's really just a snapshot of saying, here's a generation mix based on the 2020 business-as-usual mix, which presumes some demand growth to that year.

We then try to forecast demand uncertainty over time, which I agree is a significant uncertainty, and one, why I actually like to use a more dynamic programming approach that looks at flexibility over time.

Actually, if I may, I can comment on the diurnal nature of a lot of resources. Again, I think you're absolutely right that if you're going to truly implement this, you'd want to look at those costs. But on a long-term basis the diurnal nature of the resource output, say from solar, which you can -- is very easy to guess, of course. And one nice thing about solar is when demand is highest, it's typically during the day when you get the most solar. So that's actually a hedge for solar.

Wind, on the other hand, tends to blow probably less on the hottest of all days. Again, that would be an important thing to consider. But when you're looking at the systematic risk I think you'd probably find that it's uncorrelated with a lot of the other uncertainties.

So, again, in terms of a realistic planning issue, clearly you'd want to take that into account.

MR. SEZGEN: And my second area I would like to talk about is the -- we have to do multiyear plans. And then here in the example we're looking at 2020. And, as you know, some of our contracts are rolling off say 2010, '11. And then we have to sort of -- do we do portfolio analytic just for each year? And how do we stitch these different years to one another? That seems to be sort of a complicated process because there may be conflicts between year to year as to what's in the frontier.

Another issue is if we're going to look at reliability as another option, this construct different reliability levels will generate different frontiers. You almost have to look at it a three-dimensional surface to make choices between environmental, reliability and cost metrics.

The second general area I would like to talk about is in this construct everything needs to be probablistically modeled at the same time, whereas we don't believe all uncertainties should be assigned probabilities to unless there's good data supporting that probablistic characterization.

For example, when our load changed because of CCADA departures and again, resource availability in terms of renewables, renewables costs, we don't have really good data as to how we can assign probabilities to them. Let alone correlating them with all the other uncertainties in there.

So, we would feel more comfortable doing scenario analysis for uncertainties that we really have no way to assign probabilities to.

And another major concern is the volume risk is a real risk for us. And in this methodology, variations demand hydro, again the wind variations are almost ignored. And it's really hard to model those uncertainties in this construct here.

Thank you.

DR. LESSER: I'd be happy to respond to a few of those questions.

Again, I think in terms of the uncertainties that we didn't address, the risk we didn't address, you're absolutely right. And, you know, that was one of the things I wanted to emphasize, that as a caveat of our analysis that we just tried to do a fairly quick analysis of this. And if you were going to actually implement it, you'd clearly want to incorporate some of those other uncertainties.

With regard to scenario analysis of how you incorporate uncertainties that you know little about, I have several responses. One is ultimately if you're creating a scenario there's essentially an implicit -- you're essentially assigning an implicit probability to it.

And by that I mean you're probably not going to model, for example, asteroid falls on California in the year 2020. Certainly it's a possible scenario, very unlikely, but, you know, okay, makes planning afterwards very easy. But, you know, it's not a scenario.

So, when you identify these scenarios and the different uncertainties that occur with that, or different attributes that are consistent with those specific scenarios, if you fail to identify any and -- or look at what the probability of those specific scenarios are, then you essentially have an exercise that's of no value.

The reason I say that is because ultimately you want to know is the scenario I construct going to happen. Do I really need to worry about it. Is it a high-likelihood scenario.

Secondly, what you can do is even for those variables that you have little, you know, formal -- let's call it regulatory uncertainty; that's certainly been mentioned in the past. Now how you model regulatory uncertainty, you probably wouldn't say it's modeled as, you know, independently distributed with -- of, you know, whatever. Not going to be the case.

But what you can look at is how would regulatory uncertainty affect your overall costs and overall decisions. And you can determine at what level does it start to matter.

That's one of the reasons I like to use

dynamic programming approaches. Because then I can check uncertainties that matter and those that don't. And I can eliminate those that don't. And then focus on just the ones that do, and devote resources to.

Is there a way I can, in fact, devote resources to reduce those specific uncertainties that I've identified having a very large impact on what I ought to do today. Because ultimately, you know, -- and again, you're absolutely correct when you're looking at -- you don't want a snapshot, you want a path over time of what do we do.

And the best way to look at that is with some sort of essentially a decision tree that says, well, today you do X; then if something happens next year, you'll want to do Y. But if it doesn't you'll do Z. Because what you're most concerned with is what do I have to do today.

And then as the world unfolds and the state of the world becomes resolved to some extent, then you can redo your analysis and essentially incorporate flexibility into your modeling process.

I hope that's -- that's sort of a long-winded answer -- I hope that's helpful.

MR. SEZGEN: Thank you. I was just wondering, to do dynamic programming, do we need to stay with this construct? Because --

DR. LESSER: You can actually use aspects of this construct. Essentially you can use dynamic programming applied to different portfolios. I mean I've done that before, so. It would obviously, you know, takes a little more analytical horsepower, but it certainly can be done.

And you can incorporate demand uncertainty, as well. And that would also be a good aspect of incorporating the Commissioner's question regarding efficiency resources at the same time.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions? Come up to the mike, please.

MR. JOHNSON: Good afternoon. I'm Raymond Johnson with Southern California Edison. I've got one comment, and then a couple of questions.

On the issue of the eightfold rise in the cost of nuclear fuel, I think I just wanted to make a comment that obviously the cost of nuclear fuel is a small part of the total costs of power coming from a nuclear plant. That's why most people -- about it. Obviously if we have another eightfold increase I think we'll start to see an impact.

It's not clear to me whether in your analysis what sort of increase in nuclear fuel prices you assumed into it between now and 2020.

The questions I have are really related to the assumptions that you made. As you rightly put it, you made some heroic assumptions, but somehow you seem to have a lot of confidence in your conclusions.

Some the things I'm concerned about, for example, you know, on slide 36 where you look at various scenarios -- various portfolios, it's interesting that you are looking at natural gas share of generation going down to about 5 percent.

So in that case you must be assuming some, you know, huge increase in the cost of natural gas; or very low renewable prices.

Secondly, for the geothermal, you got a couple of scenarios that are looking at 29 percent. Currently we've got less than about 2000 megawatts of geothermal in the state. And getting up to almost 30 percent in 2020 would look at adding another 12- or 15,000 megawatts.

So the issue then becomes, you know, one, is that capacity available; and secondly, the costs, once you start building that level, what's likely to happen is that the costs are going to skyrocket because obviously you use the best sites first. That's why we have something that guides us, for example. And by the time you are building up to 17- or 18,000 megawatts of geothermal capacity you would be basically just digging a hole in the ground somewhere.

Thank you.

DR. LESSER: Again, our analysis was just, on the renewable shares was just illustrative. And as I think one thing we pointed out earlier was that you do need to incorporate fuel and technology costs feedbacks. And, again, you're absolutely right, that once you start putting in thousands of megawatts of new resources you really want to develop some sort of supply curve for these different resources, which itself will have some uncertainties surrounding it.

But, you know, again, subject to the limitations of our analysis I think the results are robust. But, again, I wouldn't take this analysis and use it to go order any utility to go do anything.

PRESIDING MEMBER PFANNENSTIEL: Further questions?

MR. MINICK: Good afternoon; I'm Mark Minick from Southern California Edison. I just have some clarifying questions, and I apologize that I haven't read your complete report yet, so maybe we can just do some quick answers to a few of my questions, and I'll promise to go back and read the entire report.

Does renewable cost include the cost of the transmission to deliver and upgrade the systems?

DR. LESSER: I don't believe it includes transmission upgrade costs, no.

MR. MINICK: And therefore I don't think you probably included the siting risk of building those transmission lines?

DR. LESSER: No.

MR. MINICK: Okay, just wanted it clarified. Does the 45 percent renewable case meet WECC grid operating criteria? Or did you look at the risk of not meeting that criteria?

DR. LESSER: There's no -- and, again, that's a key issue in terms of integration, transmission reliability, transmission stability, all that you'd want to incorporate.

MR. MINICK: Okay. Also, you used, it looks like, a certain set of costs for renewables. Does this cost for renewables stay constant in real terms throughout the planning horizon?

DR. LESSER: I think it does. I mean, again, it's a snapshot analysis, so --

MR. MINICK: Right.

DR. LESSER: -- it's whatever the CEC Staff data was.

ASSOCIATE MEMBER GEESMAN: Yeah, I think I can clarify that because we discussed it in our cost-of-generation workshop. That was seen as one of the weaknesses in the cost-of-generation report because there was no ability to make any assumptions about changes in cost over time.

And with several of the technologies, the anticipation was a declining cost curve over time, but the staff felt that the cost-of-generation study needed to be a snapshot.

MR. MINICK: Okay, thank you.

DR. LESSER: As I discussed earlier

about say the example of solar photovoltaics, because of German demand for that, it's increased the price of photovoltaics. So, yeah, your policy decisions will obviously have capital cost impacts.

MR. MINICK: I agree. And I think if we went after as much wind as we might, I think GE's going to charge double for the turbines, but we'll wait and see.

Does this analysis consider producing too much energy in offpeak hours, and the risk of ramifications associated with that additional production offpeak hours?

DR. LESSER: No, it's not a -- again, it's at a far more basic level at this point in terms of it's not really looking at load duration curves, you know. It's not trying to match day-to-day loads at all. It's a more aggregated approach.

MR. MINICK: But you're saying more renewables, in essence, will reduce risk. But if you produce too much, in essence, hypothetical, can't use it at night, there's risk in trying to market that, sell it or dump it. There's significant financial risk.

DR. LESSER: That's true. And what you'd want to do then is -- again, if I were to use this in real terms I would want to incorporate some of those additional risks to look at what the value of the renewables was.

On the other hand, we also didn't incorporate say the solar is going to have the greatest benefit during the day when prices are at the highest, and not produce anything at night anyway, so.

MR. MINICK: Agreed.

MR. TUTT: So, Mark, that's where Edison's plug-in hybrids come in.

(Laughter.)

MR. MINICK: And I hope they work as well as we predict.

And, lastly, do you consider the effects of higher levels of renewables on reliability of the system, any kind of risk associated with the reliability of the system?

DR. LESSER: No. Again, that's something that you'd obviously want to really look at, especially when you start dealing with, say, wind integration.

MR. MINICK: Okay, thank you.

MR. KNOX: This is Bill Knox from the CEC Staff. I just wanted to clarify that there was a little bit of consideration there, we tried to use some of the results of the IAP intermittency analysis project. And so we incorporated costs of unit commitment cost estimated by our intermittency analysis project of 4-50 a megawatt hour. And a specific integration cost of 69 cents a megawatt hour.

ASSOCIATE MEMBER GEESMAN: And, Bill, do you know how that compares to the numbers coming out of the Northwest study?

MR. KNOX: No, I don't know.

ASSOCIATE MEMBER GEESMAN: I think we have that study available to us, and we probably ought to look for a comparison. It's also my understanding the intermittency assessment project, or the intermittency analysis project is hoping to publish their final report by the end of the month.

PRESIDING MEMBER PFANNENSTIEL: Further questions or discussion?

Thank you, Dr. Lesser.

MR. RINGER: We received one set of comments from C.K. Woo from E3. And he also provided us with a very short presentation. So if you'd be interested in that now at this time.

DR. WOO: Thank you, Mike. Well, having received this report a couple days ago, I just prepare a fairly short comment on the analysis performed by Bates-White.

I think some of the things that I look through, that there are a few things that I find, you know, that might need some clarification. Now, a few points I can only pick up, you know, in the last very short period of time.

And the first point is that, you know, while more renewable energy would reduced both overall risk and expected cost, well, that's true if renewable energy output is positive co-rated, as you know Jonathan has pointed out. But if high output occurs, you know, mostly during the high-priced hours, as suggested by wind energy, we might have a problem.

And secondly is that the statement, you know, portfolio risk is always estimated as standard deviation of holding -- return, I find it somewhat, you know, ironic because computing a cost variance directly actually is quite useful in that, for example, if I know my forecast, of course, of next year -- let's say it's $10 -- I know the cost variance around it of the forecast, I can construct a nice (inaudible) around it. Then I can look at another forecast that might have $15; maybe have (inaudible). And that fits nicely in the efficient frontier framework.

And I'm unsure how the percentage return type calculation would translate into that type of calculation. Again, you know, I may not be able to confirm that; portfolio risk is always, you know, as it returns.

Now, if the interest is expected return, that might be the case. But here we're interested in expected cost.

And another thing is that year-to-year fluctuation in electric output from a windfarm, unsystematic risk you rarely find, no, I don't think so. In that, as you put in more and more windfarm in your portfolio, and the output bounce around, you know, from year to year. That will make your procurement cost also bounce around. So I think that is relevant.

Well, this is from the Cal-ISO from Yakout Monsour. So I see that, you know, this quite a bit of bouncing around here; from day to day, month to month. And probably year to year. As you have more windfarms coming online.

And I think to look at this, you know, more properly, let's go back to a very simple example of cost of procurement. A load-serving entity, such as PG&E or Edison, they procure from three sources. Very simple three sources. I'm not even trying to do more than that.

There's the spot market; there's the forward market; for forward market I would include forward contracts, bilateral contracts with specific generators; and then there's renewable energy suppliers.

And you always have some spot market transactions because the load-serving entity random sales obligation always turn out to be higher or lower what you contracted. And there's no way around it, otherwise life is easy, because say all you need is just contract exactly what you forecast and we're done.

And therefore the procurement cost is sum of three terms. One is the residual -- position. And probably PG&E can add, or Edison can add more to that. Every day there might be more or less demand. And then wind output or any kind of renewable energy output can be more and less than your sales obligation. So they are transacting on the spot market.

And then there's the forward purchase at a fixed price, or fixed amount of megawatt hours. And then there's the renewable contracts also at a fixed price, but the output may vary from day to day, month to month, year to year.

Then the question, you say what are conditions that would lower the load-serving entity's expected procurement cost. Well, if the sale was always low during high-price hours, well, you are lucky. But, unfortunately, order evidence shown that as the low rises, so the sales prices move along with it.

The next one, forward market price, is less than the expected spot price. Well, so far at least based on the work done for (inaudible) and elsewhere, and also NP-15, SP-15 that I did, typically you would have some forward price premium.

Then the next question is, well, renewable energy purchase cost is less than expected spot price. Well, really that's the case, life is also easy because I can just buy more renewable energy.

The last one is that renewable energy output is always high when prices are high. So you either reduce the spot purchase or -- to make sales at high price. Life is good.

But, this case validity require two assumption. Not only the renewable energy output and market price are positive co-rated; and in fact, you require additional condition the covariancy fact that means that the movement, the gain from the co-movement, actually can offset your above-market cost from renewable energy.

Well, my question, you know, to everyone in this room is that, do we have strong evidence on either assumption. We got to the first one, certain renewable energy I think move along with market price. Solar, that's a good example. Some may not, like baseload units, geothermal, biomass, that's very flat load, probably not move along.

But so far wind energy seem to be a dominant renewable supply. And evidence so far has shown that the correlation, I don't believe, is positive. But someone can help you on that.

And the next question is, well, do we have a covariance effect greater than above-market cost. That I cannot tell you because I haven't done the work.

Anyway, well, the next two slides I won't go through, but that provide a very simple algebraic statement of the conditions here.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, C.K. Yes, Eric.

MR. WANLESS: Yes. My name is Eric Wanless and I work with the Natural Resources Defense Council. I just have a brief comment, I guess, just in support of the notion of the portfolio analysis approach.

At NRDC we support moving towards something where we evaluate portfolios to minimize risk. And I think we've heard today that this is kind of a first pass at things, and there's a lot of room to improve upon it. But we'd just like to voice our support for continuing this work and think it's very important.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

DR. YANG: We have a brief response to C.K.Woo's comments. Thank you very much. It's a very useful comments. And we'd like to actually clarify.

First of all, our analysis is more like expository -- point portfolio analysis in order to illustrate the impact of the portfolio diversification in terms of reducing cost and risk.

So, in this case it doesn't have to be -- the first point is that the necessary condition for this to be true is that the renewable energy output has to be positively correlated with the spot market price. And in our analysis it doesn't have to be as long as the correlation is less than 1, then portfolio diversification effect actually takes place.

And as the, I think the presentation page 18 shows, so we start with the portfolio, the fossil fuel portfolio. And if you add renewables, let's assume that the renewable cost is higher than the existing fossil fuel technologies. Then that will obviously increase the cost, but it will reduce the cost.

And if you stay that way then it doesn't tell the story a lot. But, if you remix it, remixing means that the (inaudible) and reoptimize it. Essentially what it does is that since you reduce the risk, it opens the window for lower cost, higher risk technologies to come in so that after the optimization you will have the lower cost portfolio with the same risk, but the result is which is the equal risk minimum cost portfolio that we have shown. So that's the first response to the first bullet.

And the second response is that the probably, I think always is too strong word, probably, most likely would be a much better word. But looks like there's a confusion about the timing of the analysis.

Our portfolio analysis more like a long-term planning thing, looking for 10 to 20 years. So we didn't look at the volumetric risk, demand uncertainties and all those. So, essentially that's why our only period return analysis is year-by-year, rather than the short-term volatilities.

But if you're interested, if the portfolio concept is applied into the short-term one, then definitely the wind variability and demand uncertainty will play a very important role.

So in that case, maybe, as you point out, the positive correlation between the spot market price and the renewable is the necessary condition may be true. Because that is the short-term volatility, and you're looking for the instrument like purchase for renewable spot market, and looking at the value at risk, and then calculate the cost of capital or cost of cash flows versus the standard deviation associated with the cost of cash flows. But in this case we didn't look at that.

And the last point is the wind variability. And this is, again -- we didn't completely or comprehensively include all the risk. And for this expository analysis we decided not to include the wind variability for two reasons.

The first one is that this is starting point, so it would make -- this is starting point, so we like to emphasize the portfolio diversification and the impact of the portfolio risk first before we refine the analysis.

And the second point is that if you really look at the global or the big diversification schemes, then the wind variability risk may be reduced. Because if you look at the wind variability, but if there's a different wind directions and all this, and the future -- market, that risk may be diversified away. So it doesn't really use this, it's not at risk.

But if you're looking for the utility procurement point of view, which is a utility windfarm, that wind variability will, in fact, act as a very critical role in terms of calculating the cash flows and the resulting volatility of the optimal level of the windfarm in order to maximize the profit.

In fact, actually Bates-White performed a very similar analysis for the utility -- and we used the portfolio analysis. But this would be very different from what we have presented so far, because it's short-term analysis, multi-period, value-at-risk analysis, which is very similar to what you have proposed in terms of analytical terms, as well as the presentation that you have just made.

DR. WOO: May I just have one quick response?

ASSOCIATE MEMBER GEESMAN: Sure.

DR. WOO: The market price issue is an

important one in a deregulated world. I would agree with you if you just look at the resource cost, per se, as an integrated utility, self sufficient, never had to transact in the market.

But to the extent that you're transacting in the market, the correlation between market price, whether this is a one-period, two-period or longer period, you still have to worry about when does your output from any -- resource would come out during the market condition.

And otherwise now we have in this, myself, contradicting -- on one hand we claim solar energy is wonderful because it follows load and matches up with market value. And then we turn around and say, no, it doesn't really matter to think along those lines.

So, I don't know which one is correct.

DR. YANG: Okay. I think your comment is right, but that was not our purpose of the study. Seems like there is a mismatch between that.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other comments here? Where do we go now, Mike?

MR. RINGER: I'd just like to check and

see if there's anybody on the phone lines before we go on to the next presentation.

MR. SCHILMOELLER: This is Michael Schilmoeller with the Northwest Power and Conservation Council.

And I just had -- actually had a response to the previous speaker, the one prior to this one. And it had to do with wind integration costs.

The wind integration cost that we use in the -- I think David Vidaver asked about this -- were $5 a megawatt hour up to 3500 megawatts, and about $11 a megawatt hour above that, for megawatts above that, up to a maximum of 6000 megawatts.

And I just spoke with a fellow here who's been more involved in that forum. And he says that the work that they've done over the last year tends to support that.

Thank you.

MR. RINGER: Okay, next I'd like to introduce Mark Minick of SCE who'll give us an overview of SCE's planning.

MR. MINICK: Good afternoon. I'll give you a brief summary of Edison's work in the last

LTPP. But first I'd like to say a few things about resource planning, since I've been doing it for about 25 years. I think I started working in system planning about when Tim Tutt was still at Edison. Tim has since moved.

The most difficult thing for me is not the mathematics, and some of the things that we can quantify and assess, it's the things we can't quantify and assess.

And for those who don't know what I'm talking about, let me give a few examples. One is blackstart. We've been trying to deal with the ISO for the last couple of years trying to identify the quantity and location of blackstart resources. And have been somewhat unsuccessful, besides the fact we can identify we need it.

So when we do resource planning and a lot of portfolio analysis we have things like this, and voltage support and VAR support and the locations it's needed. And changing demographics in our system that are almost impossible to quantify or assess.

With that, let's go through this presentation quickly because we're a little bit behind and I want to get you back on schedule.

I'll identify the major risk areas that we've basically taken a look at, and explain the risk assessment process and the candidate selection plans.

Basically we do these things in our scenario analysis to come up with what we think is the ability to produce -- I don't like the word optimal, but it's here -- a reasonable least-cost fit resource plan.

We look at system reliability and measures that we typically use for that are resource adequacy, meaning do we meet all the requirements, the regulatory requirements, the local area reliability requirements. And do we have adequate transmission to deliver most of the resources.

This is based on a 15 percent planning reserve margin. And in some cases we use a worst case criteria.

We also take a look at environmental considerations, resources with lower greenhouse emissions, more energy efficiency, more efficient resources.

We also look at transmission-related issues, voltage, stability, criteria on our system for how the grid runs; do we meet WECC operating criteria; do we meet all ISO operating criteria. In other words, can we build a resource plan that truly is operable, that meets our customers needs.

Then as far as price stability we look at cost minimization under the various objectives. We look at financial risk management and optimization of our commitments. And by optimization of commitments, meaning can we best use the resources we have and the contracts we have in an optimal fashion.

But as has been stated by other parties here, we have loading order objectives by many Commissions. So in many cases, doing the most amount of energy efficiency we can in a cost effective basis, demand response, and meeting renewable targets limits the amount that we can otherwise do. Basically it's meeting most of our needs with these criteria, so we have a little bit of need still left.

And then we look at using distributed generation, or if it's going to be incorporated, and clean and efficient fossil-fired generation. The reason for the clean fossil-fired generation is twofold.

One, they do appear to be the least-cost resources in the short term. Maybe not in the long term. And we have to have control of our grid, meaning in most cases we have to have dispatchable operable resources in the basin.

And I'll tell you something that isn't a secret, you know it and you've probably heard it before, we cannot import 100 percent of our power and still have an operable grid. We do have to have resources in our basin or in our area to run our grid.

Again, we use one-in-ten-day criteria. I think this is what the Commissions have asked us to use in the past. I tend to also agree with it.

The one-in-ten criteria is equivalent to a 15 to 17 percent planning reserve. The CPUC has adopted this as a highlight. We, in essence, found the 17 percent was more applicable for our system. But we've been using the 15 percent because most parties have been using it.

We estimate the amount of unserved energy, expected unserved energy in all the cases that we take a look at during our simulation modeling.

And we assume that other WECC regions

also build to a 15 percent planning reserve margin. Now, this is an assumption. We've taken a look at historical actions on the part of the other regions at WECC. This isn't a bad assumption, but it isn't necessarily the most direct assumption.

In some cases, controller has built more, in some cases they've built less. So, munis often build more because of the size of new resource additions to a small muni might push in the 20, 25 percent reserve margin category for a certain period of time. But over the long term we think that a 15 percent margin is reasonable to build out the regions.

You can build a resource plan to, in essence, balance financial risk or customer costs. In many cases if you want to minimize financial risk -- in this particular example, and this is just an illustrative example -- you would have a little higher cost, but you would have a probability of being in a band would be much smaller. So, you would somewhat lower your risk.

If you wanted to minimize costs you could basically do lower cost items, but you'd have much more risk.

This, again, is an example. And you've seen other presentations today that show this. When you build different scenarios they have differences in cost and they have differences in risk. In this case this is differences in emissions.

As we've shown in our LTTP filing, we came up with conclusions that are somewhat similar to the CEC's that I saw on Monday, that adding more renewables to our resource plan between two scenarios came up with a reduction cost of approximately $125 a ton for GHG.

There may be better ways to reduce CO2 if that's your only function. If it's also to lessen risk and increase hedging ability for gas prices in the future, then maybe GHG reduction and risk should be lumped together. And in that case you might want to use more renewables.

We do use stochastics for various variables. We look at stochastics for load, gas price and power price. In this case the power price is the market price. And we basically look at multiple scenarios and how they affect risk and how they affect unserved energy and costs.

Lastly, we look at different kinds of

uncertainty. Now, we've listed here some of the uncertainties. And some of these uncertainties, in essence, can't be modeled. The biggest uncertainty is retirements of aging facilities.

As the Commission well knows, as well as everybody else in the room, we can't predict with a high degree of accuracy, retirements. We have no control over retirements. Retirements are market decisions by the people that own most of the fossil resources.

We did make an estimate of what we thought was a reasonable amount of retirements in our long-term procurement plan. And to people who ask me, well, what is retired so far. And some people actually thought no retirements have occurred. There have been retirements. A couple thousand megawatts since the market has started.

Transmission access we can't quantify very well. We thought, in essence we had a transmission line approved, and it's not now approved. So to say what is it going to cost me to get other transmission lines in the future, and can I get them, and when might I get them, I can't definitively answer most of those questions. Except, we're going to try.

The same thing about renewable generation. State initiatives for solar. We've implemented in our resource plan what we think is a reasonable schedule for the solar program. I have no idea whether it will come to fruition. That's something we just take for granted when we put it in our particular runs.

Departing load is one that I haven't forecast. And in this particular analysis of our LTPP I did not forecast. And personally, I don't want to forecast if we're going to lose a load, when we're going to lose it and how much and how might that affect my resource plan.

Basically what I can do in my plan is to make sure that I'm not fully committed for 20 years with all my resources, and I have some flexibility so I can meet those criteria if they are to occur in the future.

In selecting a -- resource plans, and we only looked at I think four resource plans, but they're basically only two. There's a resource plan that looks at what we think is an Edison estimate of load growth; and a plan that we looked at a lower load growth that was similar to, but not exactly, the CEC load growth.

We thought using those two load growth scenarios with different amounts of renewables, energy efficiency were all the variables we really wanted to change. Now, we could build 20 or 50 or 100 scenarios or portfolios or whatever you want. To be totally honest we didn't have the time or the manpower to do that.

We thought these particular analyses gave us a big enough range of possible needs. And if you've read our resource plan filings, under one case there's no need whatsoever. In fact, there's probably 500 to 1000 megawatts of surplus. In the other extreme there's probably 1000 to 2000 megawatts of need.

That's a huge difference in ten years; I'm not sure we could meet either end of the spectrum if we started now. But, we thought four LTTP scenarios were enough.

We could take a look at some financial risk, system reliability risk and environmental implications. In many cases we're not going to build a resource plan that don't meet what we think are prudent reliability criteria; and that we could, in essence, financially fund if that were the case.

Lastly, this is a summary of what we do. We take a look at system reliability, price stability, environmental considerations. We perform stochastics on load, gas and power price.

We develop some candidate scenarios for analysis. And then we -- results in a balanced resource plan, meaning we try to make sure we meet all these criteria balanced in our long-term plan.

That's the end. Questions?

PRESIDING MEMBER PFANNENSTIEL: Questions? Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Mark, I want to thank you for your presentation. It is, I think, most responsive that we've gotten from your company for several years. And I think it fleshes out a lot of the uncertainties that many of us had about how do you go about doing resource planning.

I should say personally it confirms most of my worst apprehensions. But leaving that aside, tell me how you think the regulatory system should address fuel price risk, and the problems of moral hazard that fuel price risk presents.

MR. MINICK: I think some of the work you're doing now is a reasonable start down the path in how we should take a look at fuel price risk. You and I have been around long enough to know that we're never going to forecast price correctly.

But if I was to guess right, I'd guess there's probably more chance it's going to go up than down. But, I agree it isn't symmetric. I don't think it should be treated symmetrically.

But I agree with the directions you're going, and I think we need to work on it together to try to find some middle ground that's a reasonable compromise of the risks.

ASSOCIATE MEMBER GEESMAN: Now, you've been at the company for a long time. Do you recall when the last time was that you didn't have full recovery on a fuel price increase?

MR. MINICK: No.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Mark, as we're moving into a world, an RPS world where 33 percent looks like the next step, it seems to me that it's going to require some planning changes and operational changes on the part of the utilities.

Do you think that your current planning process is sufficient to handle 33 percent, 33 percent renewables?

MR. MINICK: We can model 33 percent in our models. And my experience at the utility isn't just in planning; I've worked in operations, also.

And the bigger fears are in operations. We can model the effects of 33 percent. We can take a look at the costs of 33 percent. We can take a look at the risk minimization of 33 percent.

Right now I don't think we have good enough studies to say it can truly operate a grid with 33 percent, especially what is the mix going to look like. If we take, let's make it all wind, I have real concerns. Let's make it all solar, it looks better because that's when my peak usually happens and I don't have these declining production factors during the course of the hours.

We're going to have to seriously take a look at how we incorporate this, and how we can do it over time. And you've heard many people say we're not trying to necessarily avoid getting to 33 percent. It's the timing and how can we get there the best way possible, by maintaining reliability and building a grid that's truly operable.

And I have real concerns that most of the renewables are outside the basin. As I said before, we can't import all our power. The physics don't allow us to run a grid like that right now.

And so we're going to have to take a look at how do we do it over time; can we get the appropriate transmission built to incorporate bringing this power in and still run the grid.

PRESIDING MEMBER PFANNENSTIEL: Your discussion that you just gave me, which is quite compelling, but it's all in the future tense. Are you doing this analysis now? Have you begun to decide both the longer term planning and the operational implications of 33 percent?

MR. MINICK: We have started some work internal, but it's at the very infancy stage. We're working with the ISO on some of their analyses for the 33 percent. We're taking a look at what the Northwest has done, what the Germans have done, and what other people have done, and how they incorporate those things into their system.

And then we're going to have to do a lot more transmission planning, to be honest, from our transmission planners to say, okay, will this really work; do we have the right transmission lines in the right places; do we have the right voltage support and things like that.

PRESIDING MEMBER PFANNENSTIEL: Because I don't think we should wait for the next IEPR cycle at this Commission to start really working with the utilities and understanding what your constraints are, and what your concerns are. I just want to know from you that, in fact, this is work actually underway at Edison.

MR. MINICK: Certainly we're looking at it. Again, I'm not a transmission planner. We could bring our transmission planners up and give you more detail on what they might be looking at. To be totally honest, I haven't seen the last studies in a few months, so it's --

PRESIDING MEMBER PFANNENSTIEL: Right, but that's only one of the pieces, --

MR. MINICK: Right, it's only one of the pieces.

PRESIDING MEMBER BYRON: -- we agree there are many more.

MR. MINICK: And I am on the committee

that talks to the ISO on a weekly basis about their study for intermittency and incorporation of those resources.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Questions? No other. Thank you very much, Mark.

MR. RINGER: Okay, next we'd like to get into the implementation discussion. And for that will be David Vidaver of the CEC Staff.

MR. VIDAVER: Good afternoon. Thank you. Just what I wanted to do is walk into a dispute between a bunch of PhDs on whether portfolio analysis or scenario analysis was the way to go. But that's what I'm here to do.

I also wanted to say that I happened to look at my metals portfolio the other night, and uranium is up about 270 percent over the last three years. You should also know there's some commodities you shouldn't take physical delivery of. And if anyone has friends who want pork bellies for Christmas, come see me.

We've done, we being the regulatory community, the utilities, consultants, et cetera, have done an incredible number of studies that have a tendency to sit somewhere, or they're picked up and waved vigorously by someone and they don't really implement -- they aren't really implemented, they don't impact policy, they're somewhat ignored.

The topic I'm here to deal with today is how risk assessment of the type that I think we all agree need to be done, can be incorporated into a planning process in a way that actually informs policymakers of the implications of the choices that are made by load-serving entities.

And the utilities will, no doubt, be quick to point out how they can sort of inform all of us about the implications of the constraints that policymakers impose on these choices.

So, once we decide that these risk assessments should be done, whether we should be looking at individual utilities, we should be looking at the state's portfolio in aggregate, we have a bunch of questions we need to answer.

What should these assessments consist of; what risks should be looked at, because it's the characteristics of these risks that drive how effectively they can be evaluated and influence policy in different regulatory environments, especially the one we have right now.

So, who should do the assessments is one question. Should they be of individual utilities, or should they be of the state as a whole, or both? Should different assessments be applied to different geographic areas? Should they be performed by different entities? If they're to be done by utilities, should they be done with the direction of regulatory agencies? What types of direction should be provided? Et cetera.

And what I've sort of discovered in thinking about this over the past few weeks is that it's probably easier for portfolio analysis to be done by a broader entity at a broader level, or to be done by the utility with a substantial amount of oversight.

But trying to get a utility to do portfolio analysis, and actually have it impact policy, may be somewhat difficult. This is all just for your consideration; I'm not here to, of course, make any recommendations. Just to point out some of the pitfalls associated with expecting certain agents to do certain things.

I want to start with a quote from Robert Lempert and David Groves, who I believe are both now at Rand. It's a rather interesting quote in it discusses a concept known as deep uncertainty, which they say it exists where decisionmakers don't know any one of three things.

One is how the model that they're dealing with works. How the inputs and outputs are related to each other.

The second thing that we all need to know is what the prior probabilities are of the inputs that we are looking at.

And finally, the value function that ranks the desirability of the consequences.

And we all know how the electricity system operates. We know that supply has to equal demand in real time. We know that a heat rate will define the rate between fuel throughput and output. And it will give you carbon dioxide emissions.

There are some uncertainties about the elasticities, which give you information; tweaking one variable results in another variable's changing. But it isn't -- well, maybe it is rocket science. The complexity of all this, in effect what brings us to modeling and makes it fascinating to us, that we know all these relationships doesn't necessarily mean that we can forecast or model at all well.

Forecasts are wrong, garbage-in/garbage-out, et cetera. The second problem, not knowing prior probabilities creates forecasting problems. But we do know how the system operates.

It's the second problem that really concerns us, and that is the prior probabilities and the inputs to the system model. As we look at the risks that drive ratepayer costs and influence ratepayer costs, we'll get a better handle on why we can't agree as to what they are.

And the inability to agree on those has real implications for where this analysis gets done; how it gets considered in a formal process; how it influences procurement, resource planning and state policy choices.

So, finally, the desirability of the consequences, I'm going to close with one slide on that. That, to me, is just a political process. We all get together and decide that at any given point in time the environment, to a point, is of more concern than ratepayer costs, or the risk associated with higher costs should be considered ahead of the costs, themselves. We should be willing to pay for risk reduction. Most of this occurs in the political process, so I'm not going to go into it in too much detail.

The risks that we tend to posit as being those that influence ratepayer costs the most, I'm going to keep the list very short. There are a lot of them. I think one thing that comes out of this is if you're going to propose a very sophisticated, data-intensive process for evaluating risk, you better keep the number of risks very small. Because you just don't have the staff or the time to look at a large number of risks, a large number of futures. So I'm going to limit myself to the two or three that are most important, but I think they illustrate the point that I'm going to try and make.

Natural gas price risk historically has -- planning has focused on the shorter run and medium-term risk associated with natural gas prices. This is for a number of reasons.

For a very long period natural gas didn't really have any competition. We tossed nuclear out in 1976, I think, somewhere around the time I was born, and coal has had so many -- the environmental consequences of relying on coal-fired generation are apparent to all of us.

And for a long time renewables just

simply weren't cost effective. They were sufficiently expensive that while we dealt with them through QFs and PURPA, that they weren't really seriously considered in resource planning.

Well, in about 2000 we saw deregulation in the gas market, in the '80s we saw sudden increases in prices and gas volatility. Electricity deregulation accentuated this. We saw the typical long-term gas contract go from 20 years at a fixed price to much shorter. It's my understanding that a long-term contract in gas right now is three years.

And the contractual relationships between merchant generators and utilities are such that the utility takes over the gas price risk anyway. No one's willing to sell fixed price gas to you. And certainly not for ten years. And at a substantial premium, I understand, for three.

We can expect further structural changes in the gas market to just accentuate that volatility, and perhaps lead to substantially higher prices. Lower 48 production is declining; Canadian production is going to decline unless Canada and Alaska try to develop resources which are going to cost quite a bit to extract.

If we go to LNG we have issues with lumpy infrastructure. We also have issues with the fact that a study recently pointed out that in the next ten years, maybe half the global LNG market is going to be supplied by a very small set of countries that, going over the list there are many in the Middle East and Asia that are politically unstable; some of which the United States is not at the best of diplomatic relations with recently.

And the very small number of countries holds open the possibility that we will have a GPEC. That for prolonged periods of time gas exporting countries will be able to sustain prices well above production costs.

But what's really important here is because of all these variables, we have no idea what the gas price is going to be in 20 years. We can posit a probability distribution and it will probably be pretty wide. But if we're talking about worst case scenarios, which is what we tend to look at when we're building flexible portfolios that keep us from really suffering should things go south, we're talking about probabilities of very high gas prices.

So, if I were to say, well, the probability of the gas price being $12 real seven or eight years from now is 3 percent, well, another person could quite reasonably send out significantly less than 1 percent; someone else could say, no, it's 12 percent. These are all reasonable assumptions to make.

And if you're going to conduct portfolio analysis, where you're specifying exactly what these probability distributions look like, and you're going to take those estimates to the bank, you better realize that some of your results may depend on the individual assumptions about probability distributions that other people don't necessarily agree with. And I'll get into why that's important in a minute.

Technology risk suffers from the same problems. Historically we haven't focused on technological advance. In planning in the '80s and '90s we talked about declining heat rates for STEGS and new gas-fired units. We really didn't concern ourselves too much with what the costs of, the planning costs of renewables were, and the rate at which they were going to decline, et cetera, because they had so far to go to be considered in some kind of competitive marketplace with gas. Again, coal and nuclear weren't options.

Well, we're now in a new world. We have a large number of renewable technologies that are cost competitive with gas straight up, or they will be within five or ten years.

We have higher gas prices which will make those alternative technologies, alternatives to gas, far more competitive. We have very uncertain carbon costs, which is the subject of one of the next slides, which will make gas more costly relative to resources which don't emit carbon.

And finally, we have an increasing need for baseload energy on the part of the utilities. And this may not come to the fore until 2011, '12, '13, depending on the utility, depending on which transmission lines are built, depending on assumptions about load growth, et cetera.

But by the first couple years of the next decade we're going to see utilities procuring larger amounts of baseload energy. And in this environment renewables are eligible. They might not be eligible for an RFO where you need dispatchability, you need blackstart. The number of renewable technologies that can provide that are few in number; and some of them are very expensive. But this is changing, so technology risks and consideration of technology risk is far more important.

However, you can't predict how technology, the costs of energy from various technologies are going to decline over time. We see these lifetime profiles of new technologies, where assuming they survive infancy, and there's some breakthrough, the costs decline sporadically, but rapidly. Maybe by 90 percent over the first few years of their existence.

And then they mature and they slow down. And you end up with technologies whose rates of improvement, from a cost perspective, are still dropping, but for how long they will drop and how quickly they will drop, becomes uncertain.

Wind would be a good example of this. Most people think that wind technologies will continue to show cost improvements in the low single digits over the next few years. But there are people who think that may come to a stop.

Another thing that's uncertain, as I

think several parties here have pointed out, the steepness of supply curves is uncertain. Where you have to go to the fuel, wind or geothermal, one can reasonably expect that projects that are being developed are the lowest cost projects available, given the transmission system.

As these technologies, the penetration levels of these technologies increase, we're going to see increases in their costs for any one of a number of reasons. This, of course, may be offset by technological advance in those technologies that can be offset by.

It can even be offset by our policy choices. I'm sure that Mr. Minick would argue that some of the more pessimistic assumptions that Southern California Edison made about future renewable costs at high levels of penetration in the portfolio might be reversible if we expand the set of renewables that his company could procure.

So, depending on what our renewable policy is, you could see substantial decreases in costs holding the technology costs then over the next few years.

But what's important is we can't come up with a probability distribution for these changes in the costs of energy from these technologies with any real degree of certainty.

And finally carbon risk, which is the most fascinating one of all. Carbon costs are arguably simply a function of the policy choices that you make. You can set them with a pen stroke and say, okay, carbon's 30 bucks; that's what you're going to have to pay.

You can effectively set them if you have a cap-and-trade program where you say, here's the cap, here's how we're counting what your carbon profile is currently. Go out and deal with this.

And if you have a trading program where you can actually trade with different industries, well, depending on the industry you can trade with, the cost of meeting carbon reduction requirements, you know, can vary.

And I don't think anyone will ever agree on what true carbon costs are, because they can always be set administratively. Someone can always claim you just set the wrong number. And the carbon costs the utilities should face, or the value that society should place on carbon is double what you have set it at.

So, add to the fact that there are

regimes that have been proposed where you cannot buy offsets from another industry. Well, if you can't do that, at $10 a metric ton for carbon, you may be forced to install control technologies or to change your portfolio in such a way that it costs you, I believe Mark said their estimate was $125.

So, if you're trying to develop a probability distribution for carbon costs for next year, good luck. If you're trying to do it 20 years from now, good luck there, as well.

And one of the other significant factors to be considered is that if we make decisions today which restrict the ability of utilities to lower their carbon profile at a given cost, increase the cost of doing that, we actually will be impacting the ability, no doubt, of the political system to impose those costs in the future.

If we make decisions today which preclude future carbon reductions, it's very likely that we won't request carbon reductions of such magnitude.

What are the implications of these three particular risks, what are their characteristics, and what are the implications of those for the framework within which we try and apply this analysis.

Well, they're all very very long-run risks that no one is going to be able to agree on with any certainty about how they're going to move forward in the future. What probability distribution even exists today, much less what probability distribution will characterize these risks going out about ten years.

So, one thing that seems pretty obvious is that the planning horizon should be extended. Now this doesn't mean that every single study done by regulators, utilities, consultants paid by either of them, et cetera, should go beyond ten years in excruciating detail.

But we do have to keep in mind that the decisions we make today have implications going out for a long time. The power plants that we build are designed to last 30, and in fact will probably last 40 or 50 years. Most of them will retain their place in the dispatch queue for 15 or 20 years. So even though we might argue, well, we'll build a combined cycle now, but in 10 or 12 years it's going to be load following; and in 15 or 20 years it's just going to be providing summer peaking capacity. That's probably not exactly true.

The utilities frequently sign contracts for 20 years. The goals that society has regarding carbon reduction extend well beyond 2020.

And finally, as Edison has pointed out in its procurement plan, there are significant costs associated with various policy choices that we make that extend beyond 2017. And that, if that's indeed the case, we should be looking beyond 2017 when attempting to quantify the consequences of the portfolios that utilities develop, that the state develops, and the consequences of the policy choices that we make.

If we're going to go beyond ten years, and we're going to claim that the future has some value, portfolios should arguably be evaluated over an entire range of discount rates. That doesn't mean that any one particular discount rate is preferable to another. In fact, it's the very notion that there will be disagreement as to what the appropriate discount rate is that encourages an evaluation of portfolio choices under multiple discount rates. So we can see how sensitive portfolio choices are to -- the desirability of portfolio choices is to different discount rates over time.

The uncertainty regarding the future costs of capital may be a third reason for looking at different discount rates. I casually mentioned this to Dr. Lesser earlier today, and he didn't like that. So I'll have to go back and talk to him. He said it was like comparing apples and oranges. And I have a hard enough time with financial concepts, and I don't really like adding discussions of fruit to them at the same time.

(Laughter.)

MR. VIDAVER: We've decided that if we can agree that these major risks are all such that the underlying probability distributions are perhaps little more than wild guesses, it becomes obvious that we need something like portfolio analysis where we model a multiplicity of futures and a multiplicity of portfolios over a long period of time.

The Northwest Power Council has -- Power and Conservation Council has done, you take major risk drivers, you get the covariance matrices right, you look at the right combination, consistent combinations of values under a multiplicity of futures. And you, of course, include extreme values, which in many people's eyes aren't really all that extreme at all.

The futures arguably that you look at should be comparable across utilities to inform policymakers. If we want to look at individual utility portfolios, and then we want to use what we observe based on looks at those portfolios to actually come up with policies, well, you should make sure that every utility is sort of looking at the same futures.

One of the observations I had with the 2006 long-term procurement plans is that if you ask a utility to look at ratepayer costs set at 95 percent probability level for the natural gas price, well, you get such divergent estimates of what the 95th percentile is, a policymaker can't look at the three results and glean any information about what that suggests for policy.

Another observation is that if you use a model that assigns probabilities to values of key drivers, such as the models used by the Northwest Power Council, such as the model articulated by

Bates-White today, that it's probably a pretty good idea to do some sensitivity analysis to some of the assumptions that you've made about probability distributions.

If you simply develop an efficient frontier you might find that the set of resources on at least a portion of that frontier is only there because you've made ceratin assumptions about one of the underlying risk drivers.

So, I think this is equivalent to sensitivity analysis or scenario analysis after you've done portfolio analysis.

Should IOUs be required to use common planning assumptions for the primary drivers. This would certainly help policymakers. If everybody looks at the same futures, well, this is what the gas price is going to be, life gets a lot easier.

The problem is that utilities actually do face different sets of circumstances. And to require a utility to choose one gas price would be -- or one estimated value for carbon going forward to use, a utility could reasonably argue that that doesn't reflect the circumstances that it faces.

But if you require a broad range of

values for these key drivers to be looked at, policymakers end up with a library of materials from which to look at the implications of the portfolios that are presented for the key variables emissions output, ratepayer cost, ratepayer risk, et cetera.

And the utility can, at the same time, say well, I've given you gas at -- I've given you a look at portfolios and ratepayer costs and risks, et cetera, gas 5, 6, 8, 10, 12 and 16 dollars, I happen to think the future gas price is going to be 6. But the policymaker concerned, and if San Diego says we think the price of gas is going to be 6, and Southern California Edison says we think that the price of gas is going to be 16, policymakers can retrieve information regarding, well, why do you think it's going to be 6. What is it about your particular circumstance that means that it's $10 lower than for your counterpart just to the north or south.

If one of them says 6 -- if San Diego says 6 and Edison says 16, one of those gas forecasters is probably going to be out of a job pretty soon. Because those particular -- that particular driver gas tracks very very well.

The underlying probability distributions can, for the three utilities, can more or less be assumed to be the same. If Edison is going to face a $6 gas price over the next 12 years, you can be sure that San Diego and PG&E will face the same price.

So there's really no reason for policymakers to think that any argument to the effect that, well, what if one utility's portfolio faces a very high gas price, at the same time can another utility's portfolio face a low one? No. It's very easy to aggregate the three assessments done by the utilities and come up with the implications of what they've done for ratepayer costs, for risks, for greenhouse gas emissions, et cetera.

Unfortunately this isn't as true for the cost of energy from nongas sources, whether they be renewables or advanced sequestered coal. And it can't be the same for carbon costs for each utility, either, I don't think.

Edison, San Diego and PG&E will probably claim that they face different supply curves for renewable technologies. And they are probably right. But if you ask them to do planning and turn back to you the ratepayer cost, risk, greenhouse gas emissions, et cetera, under varying assumptions about future renewable costs, about costs of sequestered coal, you can be sure that, one, you will get the estimate they believe that is true. So you aren't losing anything by asking for a common set of scenarios.

And you will also cover the wide range of costs of renewable energy that may be forthcoming. All of which are plausible under some scenario. We can arguably reduce the cost of renewable energy in any one of a number of ways in a pen stroke by increasing the set of renewables from which utilities can meet the RPS. You could do it simply by increasing the PTC. There are a wide variety of ways to do this.

So I think the same thing can be said for carbon. AB-32 is perhaps a microcosm of the possible carbon costs that any utility might face. There are a number of ways that you can implement a carbon reduction program.

You can end up with regimes which result in everybody having the same impact on the environment. You can have regimes that basically force everybody to make the same sacrifices to get to some end state that you like. Or you can have simple rules that the utility has to follow to get there.

So we have economically efficient regimes which minimize social costs. We have simple rules of thumb which don't distribute the costs very well. And we have even simpler rules of thumb which combine probably the worst of those two. But that's an unnecessary editorial comment.

Should we have common policy prescriptions? Well, the PUC has already weighed in on that. The holy grail is a set of regulations, a set of constraints by utility procurement that basically meets the state's policy goals in the most efficient fashion.

And this was the source of my comment. I don't think we're there yet. I think the PUC would agree that we are a long way from a set of constraints on utilities that get to satisfy state policy goals in the long run, in a way that's minimum cost.

We have a number of choices about the methodology or the broader class of methodologies we can use for analysis. We have a number of choices about who can best do it, what the geographic level is in which we do these analyses.

We cannot do either scenario analysis or portfolio analysis without the utilities. They have far and away the best models for evaluating their own portfolios. They have knowledge of operating constraints that they face; knowledge of the transmission needs that they have.

And we can, of course, utilize that information and try to incorporate it more formally into whatever process that we like. But we are not going to be able to do this without their cooperation.

On the other hand, the 2006 long-term procurement plans indicate that there are types of analysis that the utilities are reticent to do. Those are ones that require them to make assumptions about things beyond their control. Whether, as Mark said, it would be the retirement of aging power plants, what policies might be in place.

In order to facilitate utility analysis of particular policies, you've typically had to tell them, assume this policy's in place.

And statewide and WECC-wide assessments require assumptions about what's going on in the rest of the WECC, what the munis instate are doing, what's being, as I said, what's being retired. And even what is being added, utilities are reticent to do. And are arguably, I think they might agree to an extent that they're not the entity that is best qualified to do it.

Now, having heard a sort of methodological dispute about which of these methodologies, scenario analysis or portfolio analysis, is preferable, I'll return to my initial observation.

And that is that if you ask utilities to do portfolio analysis and you do not tell them what those underlying probability distributions are, you will get three reports back that probably have probability distributions that are so diverse that you will not be able to aggregate them up and have any clue as to what you should do.

That isn't to say that this type of analysis isn't very important. It's, I think people here have made an excellent case for its value. But, I believe it's something that if it's to be incorporated formally into a procurement and planning process, it, at the very least, needs to start at a regulatory agency.

I don't think starting it at a utility is perhaps the most efficient way to do it. I think what happens is that unless what is apt to happen, based on my observation, is that unless you prescribe to them what they should assume in their planning process, and in their resource plans, unless you prescribe what that probability distribution is supposed to be, you're going to get back a product of limited utility.

And in prescribing that you defeat some of the purpose of undertaking portfolio analysis. It's that very uncertainty about the probability distributions of these major drivers that you want to deal with effectively, efficiently, and in a fashion that acknowledges the serious long-term risks that ratepayers may face.

And as I'm sure the Commission realizes, portfolio analysis, itself, doesn't value risk reduction at all. It gives you an efficient frontier from which you may choose portfolios for which you cannot reduce risk, given the cost; or you cannot reduce cost, given the risk, et cetera.

And then the consultant shows it to you and says, pick one. My job's done; it's now your turn to do this.

In the presence of this incredible uncertainty, obviously the exact position of the efficient frontier and what portfolios are on it are all contingent upon those underlying distributions about which we've admitted we don't have a whole lot of information.

And in asking policymakers to choose between these portfolios, it's, of course, incumbent upon them to go out and say, well, what do consumers want; what do ratepayers want; where do they want to sit on this curve.

And there are numerous surveys which attempt to get into risk preferences of ratepayers. We have stable rate analysis, how much will you pay for stable rates. How much would you pay to avoid, to reduce the chances of being blacked out.

The type of survey -- I'm not the world's biggest fan of these surveys. There's a lot of anecdotal evidence that the results from these surveys are very very sensitive to a number of factors.

This isn't to say that ratepayers aren't risk averse. I do question, however, whether or not you can quantify that risk aversion out to three or four decimal places, or even two.

In this case you're talking about inter-temporal risk where you're basically walking up to someone and say, okay, your electricity bill is $75. How much would you pay to avoid -- on a regular basis, going forward -- to avoid paying $200 in 2013.

And I can only think of how much fun I would have answering that question if someone came up to my door. I can also imagine there's a dumfounded look on people's faces if they were actually presented with that.

ASSOCIATE MEMBER GEESMAN: Do you have a mortgage, Dave?

MR. VIDAVER: Pardon?

ASSOCIATE MEMBER GEESMAN: Do you have a mortgage?

MR. VIDAVER: Do I have a mortgage. No, I don't, but I do incur debt rather readily. I mean, -- I have my own risk preferences.

ASSOCIATE MEMBER GEESMAN: I'm looking for the long term debt. And inclined to think that the distribution of customer choice between fixed rate mortgages and variable rate mortgages might be of some parallel interest here.

MR. VIDAVER: I certainly will never take out a variable rate mortgage, yes.

ASSOCIATE MEMBER GEESMAN: Yet economists have determined that over the course of the last 30 years, probably at no point during that period has a fixed rate mortgage actually delivered a lower cost of borrowing than the variable rate would have.

MR. VIDAVER: I have to -- can I chew on that?

ASSOCIATE MEMBER GEESMAN: Please.

MR. VIDAVER: Get back to you offline. There are also people who carry around six months worth of income on their 19 percent credit cards, too.

(Laughter.)

MR. VIDAVER: But I have no doubt that people are risk averse, and I don't have a prior on whether they are more or less risk averse in the long term. I have no idea. I could be convinced either way.

PG&E called, at some point in the long-term procurement proceeding, for a need to refresh information about consumer risk preferences. They've obviously used to determine how much gas price risk utilities are going to hedge in the short run, et cetera.

I'm not sure how much policymakers will be able to take from that. I'm sure that if you did three assessments, one for each utility, of the risk profile of their customers you would come up with three distinctly different numbers. Probably all a result of exactly how you designed that survey.

I have no doubt that they are different. I assume that risk profiles differ by customer class. That San Diego has less industrial and commercial than it used to. And the risk profile, it's largely residential and customer base is, I'm sure -- or I wouldn't be surprised if it were quite different than that of the other utilities.

I'm an economist, so I will say that, well, risk and electricity bills doesn't really matter because I have all these opportunities to hedge at-risk elsewhere in my portfolio, et cetera. I don't really believe that. I think that's economists trying to desperately hang onto their (inaudible).

But consumers do have other ways of expressing risk preferences. I'm trying to offer this as something heartening for people who have to make policy in this area.

You may not have enough information about consumer risk preferences, but you do have your priors, you have your opinions about it, you glean information about it from where you can, and you make policy choices based on that, policy recommendations based on that.

And consumers do have a way of showing you that you got it wrong, if indeed you do. You get nasty letters or in Gray Davis' case, you get recalled.

So I think your priors on how risk averse customers are, are probably as good as any that a consulting firm could cough up for a utility. And some of them will be punished if policymakers are wrong.

So, at the end of a long day, that concludes my presentation. I just hope that whatever we get out of this is actually implemented and useful and used somewhere in the impacts policy. I've seen too many studies just fall by the wayside and not be used. And I caution you to carefully consider some of these institutional elements in you deliberations.

I'm happy to take any questions.

PRESIDING MEMBER PFANNENSTIEL: Any questions? Comments? Further consideration --

ASSOCIATE MEMBER GEESMAN: I had one question. You mentioned the potential to reduce costs of renewables by expanding the list of eligible renewables utilities could procure. What did you have in mind there?

MR. VIDAVER: I'm not incredibly well versed on the current state of what renewable resources meet the criteria that would encourage utilities to contract with them. Now, --

ASSOCIATE MEMBER GEESMAN: Do you have the sense that there are cheaper ones out there that they're not allowed to?

MR. VIDAVER: If the set from which utilities may choose to be RPS eligible, for example, is limited geographically, or limited by the need to deliver energy from that resource to load in California, or to deliver that energy in real time, that obviously limits the -- in limiting the set of resources, it increases the costs that the utilities would pay for those resources.

Not that there wouldn't be wonderful

reasons -- if policymakers have decided to limit that set, there are reasons for doing that. But policymakers may, at some point, change their mind and with a pen stroke encourage contracts with cheaper renewable resources located outside of California.

ASSOCIATE MEMBER GEESMAN: But you're thinking primarily in terms of deliverability constraints, not different technologies?

MR. VIDAVER: I'm not thinking of technologies. I'm thinking of deliverability and if, and as I said I don't know the current status of the RPS, --

ASSOCIATE MEMBER GEESMAN: I've got a better understanding of what you mean.

MR. VIDAVER: Thank you.

ASSOCIATE MEMBER GEESMAN: Eric.

MR. WANLESS: Yes. Eric Wanless with NRDC. I just have a really brief question. I know it's 4:00, so I'll be quick.

Being an engineer I always kind of am tempted to ask, what the heck are you going to do with all this stuff. And I still have that question after kind of going through the exercise of hearing this presentation.

I'm curious, are you coordinating with the CPUC? I don't think I see anyone here from the CPUC. But I'm curious if there's any coordination, or what vision you have for I guess interacting with the process, the long-term procurement plan process, and how this might feed into that.

MR. VIDAVER: The Commission is a party -- the California Energy Commission is a party to the long-term procurement proceeding. And has the opportunity to provide comments in that proceeding.

MR. WANLESS: I guess I would encourage the Commission to the fullest extent possible to make sure that the CPUC is being involved in this discussion.

My other comment, I guess, is I think one of the values to doing this sort of work at the Energy Commission is pulling in the municipal utilities into the fold. And is that something that you envision I guess happening in the future in terms of portfolio analysis work in the future?

MR. VIDAVER: I'm just a staff member. I will do whatever the Legislature and the Commission tells me to do. So, --

MR. WANLESS: Again, I would encourage the Commission to incorporate municipal utilities in this sort of work in the future.

Thank you.

ASSOCIATE MEMBER GEESMAN: Yeah, let me respond to both your points, Eric, because on the first I think our vision is the same level of interconnectedness and interaction between the two Commissions. That was expressed in some of Commissioner Peevey's assigned Commissioner rulings. And I think there was one joint statement that he and I authored in 2005 for the 2005 long-term procurement proceeding. So we would hope to perform the role envisioned in those several ACRs.

As regards the munis, historically until the Legislature acts, the munis tend to be trailing participants. And the trail is probably two or more years behind the investor-owned utilities.

This Commission has a tendency to hector the munis for a couple of years; and then the Legislature steps in and says, thou shalt participate.

I think realistically, in terms of the

analytic talents, we really look to the three investor-owned utilities as the most logical initial partners in some of the intellectual journeys that we take.

And I guess in response to some of the more general comments, I'm not prepared to abandon the scenarios approach that we've taken in other parts of the Integrated Energy Policy Report. I think the comments by PG&E were well taken in that regard. I think we need to pursue that and flesh that out quite a bit more in subsequent cycles.

But I have to say, as well, I think it's important that we develop a strong portfolio analysis discipline for our next cycle. And I am particularly moved by Mark's flinching at the word optimal. Because I'm inclined to make the same flinch. I really think that people have the illusion that we're dealing with lasers here --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- where we're dealing with paint brushes, the breadth of those that you use on your house.

But, at the same time, AB-57, which was enacted in 2002, speaks in terms of least-cost/ best-fit, which is an optimal consideration to guide procurement.

And I think, as some of the material Dave covered, what this Commission is trying to do, and what I think the focus of our analysis, be it in a scenarios context or in a portfolio context, is to influence long-term procurement decisions.

And those are long-term procurement decisions that get refreshed and renewed every couple of years. It's not as if you're making all of the decisions for the next 20 years today.

You're making long-term decisions on a two-year cycle. And you're going to revisit those decisions two years from now. And that's the pattern the PUC has set up. I think that's the pattern that our analytic process is well designed to reinforce.

We clearly have to do a certain amount of that work, but I don't think it'll be very well informed if we don't have the utilities fully engaged in it. And I certainly think, in terms of trying to establish key assumptions, key methodological approaches, and some general concurrence as to how we evaluate the ramifications of the results we need to try and find some common ground with the utilities to make that work meaningful.

And I say the utilities, I certainly mean all of the stakeholders, but I recognize that in terms of actually doing modeling and analysis, the principal participants are likely to be the utility companies and the Commission Staff.

MR. WANLESS: Thank you. And I just want to reiterate that NRDC is very supportive of the work that the Commission is doing, both in the scenario analysis and the portfolio analysis --

ASSOCIATE MEMBER GEESMAN: Well, you guys pushed us in this direction a couple of years ago by pointing out deficiencies in our work. And I think those were well taken comments. And it's something we've tried to respond to.

And in the same way, Edison pushed us when we adopted the 2003 report on the need to evaluate integrating intermittent resources.

And we're just barely scratching the surface on that. There's a lot more work that needs to be done.

And I think one of the things that Dave touched on was the operational. We don't have much talent on the operational side. And I think we ought to just acknowledge that.

The ISO and the CPUC are much more directly involved in day-to-day operation of the system. We need to be sensitive to those concerns, but we ought not to pretend that we're going to consciously attempt to second guess that.

DR. LESSER: I did want to add just one thing about the scenario and probablistic analysis. I don't think it's at all an either/or case. That you can, in fact, combine both of them together in a consistent manner with some of the decision analysis approaches and looking at different sensitivities and probabilities.

So I worked to meld those two together rather than trying to do portfolio analysis and do scenarios analysis and never the twain shall meet.

And in terms of the actual implementation procurement, certainly perfection is going to be the enemy of the good. And the different utilities are going to face very different constraints. And that's, you know, you may have a state level general policy of what you want, but then when you get down to say the SCE level where they are in a load pocket, clearly that's going to be -- those are realistic operational concerns that have to be addressed.

Thank you.

ASSOCIATE MEMBER GEESMAN: That's right. And I think the other side of some of Edison's comments that I should address, as well, is independent of the actual procurement decisions I do firmly believe that the state has made a significant commitment to building out the transmission system.

And I believe that we recognize that's a regional objective. And that our interests extend far beyond the boundaries of California.

The two Commissions may have a few differences over how best to do that, and over what timeframe certain decisions ought to be made, but I do think we share the commitment to see that we move aggressively for that.

And this Commission, in any event, certainly has been supportive of the federal government's role, and developing role in the southern California counties.

Do we have other comments? Anyone on the --

MR. RINGER: I think we might have one commenter on Webex.

MR. SCHILMOELLER: Oh, yeah, can you hear me?

ASSOCIATE MEMBER GEESMAN: Yes, go ahead.

MR. SCHILMOELLER: Okay -- stale now, goes back to the early part of Dave's presentation when he was talking about some of the key risk factors. And he mentioned in there that utilities will need to build additional baseload to meet growth as we go forward. And using the sets of analyses be helpful in that respect.

I think there's a complicating factor if we go back to direct access. I don't think utilities will be building baseload to meet --

ASSOCIATE MEMBER GEESMAN: Yeah, I think Dave said that there was a need for baseload. I don't think he -- I may be mistaken, but I don't think he commented as to whether that would be utility-built and -owned, or provided by merchant generators.

The direct access --

MR. SCHILMOELLER: -- your portfolio analysis gets much more complex.

ASSOCIATE MEMBER GEESMAN: Understood. The direct access to date remains an ongoing sideshow in California. I think we'll still be debating that in 2012. So don't look for any quick resolution.

MR. SCHILMOELLER: (inaudible).

ASSOCIATE MEMBER GEESMAN: Other comments or questions?

Okay, I want to thank everybody. This has been a very productive afternoon.

We'll be adjourned.

(Whereupon, at 4:07 p.m., the Joint Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 9th day of August, 2007.